Exhibit 110

Company:	ANADARKO PETROLEUM CORP
Document:	10-Q (Q2 2016) · 07/26/2016
Section:	Entire Document
File Number:	001-08968
Pages:	50

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549

FORM 10-Q

(Mark One)

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2016
or

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission File No. 1-8968

ANADARKO PETROLEUM CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	**76-0146568**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1201 Lake Robbins Drive, The Woodlands, Texas	**77380-1046**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code **(832) 636-1000**

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer Accelerated filer Non-accelerated filer Smaller reporting company

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes No

The number of shares outstanding of the Company's common stock at July 15, 2016, is shown below:

Title of Class	Number of Shares Outstanding
Common Stock, par value $0.10 per share	510,457,469

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
millions except per-share amounts	**2016**	2015	**2016**	2015
Revenues and Other				
Oil and condensate sales	**$ 1,125**	$ 1,616	**$ 1,975**	$ 3,035
Natural-gas sales	**320**	487	**686**	1,128
Natural-gas liquids sales	**235**	229	**413**	461
Gathering, processing, and marketing sales	**305**	305	**545**	598
Gains (losses) on divestitures and other, net	**(70)**	(1)	**(30)**	(265)
Total	**1,915**	2,636	**3,589**	4,957
Costs and Expenses				
Oil and gas operating	**202**	226	**410**	522
Oil and gas transportation	**246**	283	**488**	588
Exploration	**76**	103	**202**	1,186
Gathering, processing, and marketing	**252**	255	**467**	509
General and administrative	**305**	278	**754**	585
Depreciation, depletion, and amortization	**984**	1,214	**2,133**	2,470
Other taxes	**157**	151	**274**	333
Impairments	**18**	30	**34**	2,813
Other operating expense	**7**	6	**23**	69
Total	**2,247**	2,546	**4,785**	9,075
Operating Income (Loss)	**(332)**	90	**(1,196)**	(4,118)
Other (Income) Expense				
Interest expense	**217**	201	**437**	417
Loss on early extinguishment of debt	**124**	-	**124**	-
(Gains) losses on derivatives, net	**307**	(311)	**604**	(159)
Other (income) expense, net	**(55)**	15	**(55)**	62
Tronox-related contingent loss	**-**	-	**-**	5
Total	**593**	(95)	**1,110**	325
Income (Loss) Before Income Taxes	**(925)**	185	**(2,306)**	(4,443)
Income tax expense (benefit)	**(314)**	77	**(697)**	(1,315)
Net Income (Loss)	**(611)**	108	**(1,609)**	(3,128)
Net income (loss) attributable to noncontrolling interests	**81**	47	**117**	79
Net Income (Loss) Attributable to Common Stockholders	**$ (692)**	$ 61	**$ (1,726)**	$ (3,207)
Per Common Share				
Net income (loss) attributable to common stockholders-basic	**$ (1.36)**	$ 0.12	**$ (3.39)**	$ (6.32)
Net income (loss) attributable to common stockholders-diluted	**$ (1.36)**	$ 0.12	**$ (3.39)**	$ (6.32)
Average Number of Common Shares Outstanding-Basic	**510**	508	**510**	507
Average Number of Common Shares Outstanding-Diluted	**510**	509	**510**	507
Dividends (per common share)	**$ 0.05**	$ 0.27	**$ 0.10**	$ 0.54

See accompanying Notes to Consolidated Financial Statements.

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ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
millions	**2016**	2015	**2016**	2015
Net Income (Loss)	**$ (611)**	$ 108	**$ (1,609)**	$ (3,128)
Other Comprehensive Income (Loss)				
Adjustments for derivative instruments				
Reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	**2**	3	**5**	5
Income taxes on reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	**(1)**	(1)	**(2)**	(2)
Total adjustments for derivative instruments, net of taxes	**1**	2	**3**	3
Adjustments for pension and other postretirement plans				
Net gain (loss) incurred during period	**(24)**	-	**(190)**	-
Income taxes on net gain (loss) incurred during period	**9**	-	**70**	-
Prior service credit (cost) incurred during period	**-**	-	**(1)**	-
Income taxes on prior service credit (cost) incurred during period	**-**	-	**1**	-
Amortization of net actuarial (gain) loss to general and administrative expense	**34**	13	**42**	26
Income taxes on amortization of net actuarial (gain) loss to general and administrative expense	**(13)**	(5)	**(16)**	(9)
Amortization of net prior service (credit) cost to general and administrative expense	**(6)**	1	**(21)**	1
Income taxes on amortization of net prior service (credit) cost to general and administrative expense	**3**	-	**8**	-
Total adjustments for pension and other postretirement plans, net of taxes	**3**	9	**(107)**	18
Total	**4**	11	**(104)**	21
Comprehensive Income (Loss)	**(607)**	119	**(1,713)**	(3,107)
Comprehensive income (loss) attributable to noncontrolling interests	**81**	47	**117**	79
Comprehensive Income (Loss) Attributable to Common Stockholders	**$ (688)**	$ 72	**$ (1,830)**	$ (3,186)

See accompanying Notes to Consolidated Financial Statements.

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ANADARKO PETROLEUM CORPORATION
CONSOLIDATED BALANCE SHEETS
(Unaudited)

millions	**June 30, 2016**	December 31, 2015
ASSETS		
Current Assets		
Cash and cash equivalents ($160 and $100 related to VIEs)	$ **1,394**	$ 939
Accounts receivable (net of allowance of $13 and $11)		
Customers ($67 and $81 related to VIEs)	**770**	652
Others ($76 and $84 related to VIEs)	**730**	1,817
Other current assets	**318**	573
Total	**3,212**	3,981
Properties and Equipment		
Cost	**69,610**	70,683
Less accumulated depreciation, depletion, and amortization	**37,265**	36,932
Net properties and equipment ($5,002 and $4,859 related to VIEs)	**32,345**	33,751
Other Assets ($621 and $644 related to VIEs)	**2,239**	2,268
Goodwill and Other Intangible Assets ($1,237 and $1,220 related to VIEs)	**6,237**	6,331
Total Assets	$ **44,033**	$ 46,331
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable ($172 and $179 related to VIEs)	$ **2,200**	$ 2,850
Current asset retirement obligations	**221**	309
Interest payable	**242**	247
Other taxes payable ($21 and $18 related to VIEs)	**282**	318
Accrued expenses	**267**	424
Short-term debt	**32**	32
Total	**3,244**	4,180
Long-term Debt	**15,641**	15,636
Other Long-term Liabilities		
Deferred income taxes	**4,686**	5,400
Asset retirement obligations ($135 and $127 related to VIEs)	**1,726**	1,750
Other	**4,136**	3,908
Total	**10,548**	11,058
Equity		
Stockholders' equity		
Common stock, par value $0.10 per share (1.0 billion shares authorized, 531.2 million and 528.3 million shares issued)	**53**	52
Paid-in capital	**9,638**	9,265
Retained earnings	**3,103**	4,880
Treasury stock (20.7 million and 20.0 million shares)	**(1,026)**	(995)
Accumulated other comprehensive income (loss)	**(487)**	(383)
Total Stockholders' Equity	**11,281**	12,819
Noncontrolling interests	**3,319**	2,638
Total Equity	**14,600**	15,457
Total Liabilities and Equity	$ **44,033**	$ 46,331

Parenthetical references reflect amounts as of June 30, 2016, and December 31, 2015.

See accompanying Notes to Consolidated Financial Statements.

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ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENT OF EQUITY
(Unaudited)

millions	Total Stockholders' Equity: Common Stock	Paid-in Capital	Retained Earnings	Treasury Stock	Accumulated Other Comprehensive Income (Loss)	Non-controlling Interests	Total Equity
Balance at December 31, 2015	**$ 52**	**$ 9,265**	**$ 4,880**	**$ (995)**	**$ (383)**	**$ 2,638**	**$ 15,457**
Net income (loss)	-	-	(1,726)	-	-	117	(1,609)
Common stock issued	1	108	-	-	-	-	109
Dividends-common stock	-	-	(51)	-	-	-	(51)
Repurchase of common stock	-	-	-	(31)	-	-	(31)
Subsidiary equity transactions	-	265	-	-	-	723	988
Distributions to noncontrolling interest owners	-	-	-	-	-	(159)	(159)
Reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	-	-	-	-	3	-	3
Adjustments for pension and other postretirement plans	-	-	-	-	(107)	-	(107)
Balance at June 30, 2016	**$ 53**	**$ 9,638**	**$ 3,103**	**$ (1,026)**	**$ (487)**	**$ 3,319**	**$ 14,600**

See accompanying Notes to Consolidated Financial Statements.

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ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30,	
millions	**2016**	2015
Cash Flows from Operating Activities		
Net income (loss)	$ **(1,609)**	$ (3,128)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities		
Depreciation, depletion, and amortization	**2,133**	2,470
Deferred income taxes	**(820)**	(1,187)
Dry hole expense and impairments of unproved properties	**45**	1,040
Impairments	**34**	2,813
(Gains) losses on divestitures, net	**102**	425
Loss on early extinguishment of debt	**124**	-
Total (gains) losses on derivatives, net	**610**	(158)
Operating portion of net cash received (paid) in settlement of derivative instruments	**165**	172
Other	**203**	74
Changes in assets and liabilities		
Tronox-related contingent liability	**-**	(5,210)
(Increase) decrease in accounts receivable	**922**	(105)
Increase (decrease) in accounts payable and accrued expenses	**(717)**	(198)
Other items, net	**(100)**	(269)
Net cash provided by (used in) operating activities	**1,092**	(3,261)
Cash Flows from Investing Activities		
Additions to properties and equipment and dry hole costs	**(1,879)**	(3,501)
Divestitures of properties and equipment and other assets	**900**	700
Other, net	**14**	16
Net cash provided by (used in) investing activities	**(965)**	(2,785)
Cash Flows from Financing Activities		
Borrowings, net of issuance costs	**5,275**	4,787
Repayments of debt	**(5,425)**	(3,857)
Financing portion of net cash received (paid) for derivative instruments	**(727)**	(77)
Increase (decrease) in outstanding checks	**(159)**	(109)
Dividends paid	**(51)**	(277)
Repurchase of common stock	**(31)**	(37)
Issuance of common stock, including tax benefit on share-based compensation awards	**30**	19
Sale of subsidiary units	**1,163**	187
Issuance of tangible equity units - equity component	**-**	348
Distributions to noncontrolling interest owners	**(159)**	(135)
Proceeds from conveyance of future hard minerals royalty revenues, net of transaction costs	**413**	-
Net cash provided by (used in) financing activities	**329**	849
Effect of Exchange Rate Changes on Cash	**(1)**	1
Net Increase (Decrease) in Cash and Cash Equivalents	**455**	(5,196)
Cash and Cash Equivalents at Beginning of Period	**939**	7,369
Cash and Cash Equivalents at End of Period	$ **1,394**	$ 2,173

See accompanying Notes to Consolidated Financial Statements.

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ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Summary of Significant Accounting Policies

General Anadarko Petroleum Corporation is engaged in the exploration, development, production, and marketing of oil, condensate, natural gas, and natural gas liquids (NGLs), and in the marketing of anticipated production of liquefied natural gas (LNG). In addition, the Company engages in the gathering, processing, treating, and transporting of oil, condensate, natural gas, and NGLs. The Company also participates in the hard-minerals business through royalty arrangements. Unless the context otherwise requires, the terms "Anadarko" and "Company" refer to Anadarko Petroleum Corporation and its consolidated subsidiaries.

Basis of Presentation The Consolidated Financial Statements have been prepared in conformity with generally accepted accounting principles in the United States (GAAP). Certain prior-period amounts have been reclassified to conform to the current-year presentation. These Consolidated Financial Statements should be read in conjunction with the Consolidated Financial Statements and accompanying notes included in the Company's Annual Report on Form 10-K for the year ended December 31, 2015.

The Consolidated Financial Statements include the accounts of Anadarko and subsidiaries in which Anadarko holds, directly or indirectly, more than 50% of the voting rights and variable interest entities (VIEs) for which Anadarko is the primary beneficiary. All intercompany transactions have been eliminated. Undivided interests in oil and natural-gas exploration and production joint ventures are consolidated on a proportionate basis. Investments in noncontrolled entities over which Anadarko has the ability to exercise significant influence over operating and financial policies and VIEs for which Anadarko is not the primary beneficiary are accounted for using the equity method. In applying the equity method of accounting, the investments are initially recognized at cost, and subsequently adjusted for the Company's proportionate share of earnings, losses, and distributions. Other investments are carried at original cost. Investments accounted for using the equity method and cost method are reported as a component of other assets.

Recently Issued Accounting Standards The Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2015-03, *Interest-Imputation of Interest (Subtopic 835-30)-Simplifying the Presentation of Debt Issuance Costs* and ASU 2015-15, *Interest-Imputation of Interest (Subtopic 835-30)-Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements*. These ASUs require capitalized debt issuance costs, except for those related to revolving credit facilities, to be presented in the balance sheet as a direct deduction from the carrying amount of the related debt liability, rather than as an asset. The Company adopted these ASUs on January 1, 2016, using a retrospective approach. The adoption resulted in a reclassification that reduced other current assets and short-term debt by $1 million and reduced other assets and long-term debt by $82 million on the Company's Consolidated Balance Sheet at December 31, 2015.

The FASB issued ASU 2015-02, *Consolidation (Topic 810)-Amendments to the Consolidation Analysis.* The Company adopted this ASU on January 1, 2016. In accordance with the new ASU, Western Gas Equity Partners, LP (WGP) and Western Gas Partners, LP (WES), publicly traded consolidated subsidiaries of the Company, are considered VIEs for which the Company is the primary beneficiary. Prior to adoption of the ASU, WGP and WES were consolidated by the Company under the voting interest model. After adoption, WGP and WES were consolidated by the Company under the variable interest model. While this ASU requires additional financial statement disclosure, it has no impact on the Company's consolidated results of operations, cash flows, or financial position. See *Note 17-Variable Interest Entities*.

The FASB issued ASU 2016-09, *Compensation-Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting.* This ASU will simplify the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, classification on the statement of cash flows, and accounting for forfeitures. This ASU is effective for annual and interim periods beginning in 2017 with early adoption permitted. The Company is evaluating the impact of the adoption of this ASU on its consolidated financial statements.

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ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Summary of Significant Accounting Policies (Continued)

The FASB issued ASU 2016-02, *Leases (Topic 842).* This ASU requires the lessees to recognize a lease liability and a right-of-use asset for all leases, including operating leases, with a term greater than 12 months on the balance sheet and disclose key information about their leasing transactions. This ASU is effective for annual and interim periods beginning in 2019. The Company is evaluating the impact of the adoption of this ASU on its consolidated financial statements.
The FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*, which supersedes current revenue recognition requirements and industry-specific guidance. The codification was amended through additional ASUs and, as amended, requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services. The Company is required to adopt the new standard in the first quarter of 2018 using one of two retrospective application methods. The Company is continuing to evaluate the provisions of this ASU and has not determined the impact this standard may have on its consolidated financial statements and related disclosures or decided upon the method of adoption.

2. Inventories

The following summarizes the major classes of inventories included in other current assets:

millions	**June 30, 2016**	December 31, 2015
Oil	**$ 111**	$ 116
Natural gas	**28**	36
NGLs	**77**	64
Total inventories	**$ 216**	$ 216

3. Divestitures and Assets Held for Sale

For the six months ended June 30, 2016, the Company received $900 million in net proceeds from divestitures and recognized net losses of $102 million from divestitures and assets held for sale.

Divestitures The following divestitures primarily related to assets that were included in the oil and gas exploration and production reporting segment:

- The Company sold certain U.S. onshore assets in East Texas/Louisiana with a sales price of $107 million, for net proceeds of $99 million, and recognized a gain of $13 million.
- The Company sold certain U.S. onshore assets in West Texas for net proceeds of $138 million, with no gain or loss recognized.
- The Company sold certain U.S. onshore assets in the Rockies for net proceeds of $593 million, and recognized a loss of $53 million.

Assets Held for Sale Certain U.S. onshore assets included in the oil and gas exploration and production and midstream reporting segments satisfied criteria to be considered held for sale during the second quarter of 2016, at which time the Company remeasured them to their current fair value using a market approach and Level 2 fair-value measurement and recognized a loss of $50 million. The sale of these assets is expected to close in the third quarter of 2016.
Gains and losses on assets held for sale are included in gains (losses) on divestitures and other, net in the Company's Consolidated Statements of Income. At June 30, 2016, the balances of assets and liabilities associated with assets held for sale were not material.

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ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

4. Impairments

Impairments of long-lived assets are included in impairment expense in the Company's Consolidated Statements of Income. The following summarizes impairments of long-lived assets and the related post-impairment fair values by segment:

	Three Months Ended		Six Months Ended	
millions	**Impairment**	**Fair Value (1)**	**Impairment**	**Fair Value (1)**
June 30, 2016				
Oil and gas exploration and production				
Long-lived assets held for use				
U.S. onshore properties	**$ -**	**$ -**	**$ 4**	**$ 585**
Gulf of Mexico properties	**1**	**-**	**2**	**-**
Cost-method investment (2)	**1**	**32**	**2**	**32**
Midstream				
Long-lived assets held for use	**11**	**2**	**21**	**5**
Other				
Long-lived assets held for use	**5**	**1**	**5**	**1**
Total	**$ 18**	**$ 35**	**$ 34**	**$ 623**
June 30, 2015				
Oil and gas exploration and production				
Long-lived assets held for use				
U.S. onshore properties	$ 4	$ 12	$ 2,303	$ 1,303
Gulf of Mexico properties	17	-	25	-
Cost-method investment (2)	1	32	1	32
Midstream				
Long-lived assets held for use	8	199	484	202
Total	$ 30	$ 243	$ 2,813	$ 1,537

(1) Measured as of the impairment date using the income approach and Level 3 inputs.
(2) Represents the after-tax net investment.

Impairments during the six months ended June 30, 2015, were primarily related to the Company's Greater Natural Buttes oil and gas and midstream properties in the Rockies, which were impaired due to lower forecasted commodity prices.
In addition to the long-lived asset impairments above, the Company recognized a $935 million impairment of unproved Greater Natural Buttes properties during the six months ended June 30, 2015, as a result of lower commodity prices. Impairments of unproved properties are included in exploration expense in the Company's Consolidated Statements of Income.
It is reasonably possible that prolonged low or further declines in commodity prices, changes to the Company's drilling plans in response to lower prices, or increases in drilling or operating costs could result in future impairments.

5. Suspended Exploratory Well Costs

The Company's suspended exploratory well costs were $1.2 billion at June 30, 2016, and $1.1 billion at December 31, 2015. The increase in suspended exploratory well costs during 2016 is primarily related to the capitalization of costs associated with appraisal activities in Côte d'Ivoire. There were no material charges to exploration expense during the six months ended June 30, 2016, related to suspended exploratory well costs previously capitalized for a period greater than one year since the completion of drilling at December 31, 2015. Projects with suspended exploratory well costs are those identified by management as exhibiting sufficient quantities of hydrocarbons to justify potential development and where management is actively pursuing efforts to assess whether reserves can be attributed to these projects. If additional information becomes available that raises substantial doubt as to the economic or operational viability of any of these projects, the associated costs will be expensed at that time.

6. Derivative Instruments

Objective and Strategy The Company uses derivative instruments to manage its exposure to cash-flow variability from commodity-price and interest-rate risks. Futures, swaps, and options are used to manage exposure to commodity-price risk inherent in the Company's oil and natural-gas production and natural-gas processing operations (Oil and Natural-Gas Production/Processing Derivative Activities). Futures contracts and commodity-price swap agreements are used to fix the price of expected future oil and natural-gas sales at major industry trading locations such as Cushing, Oklahoma or Sullom Voe, Scotland for oil and Henry Hub, Louisiana for natural gas. Basis swaps are periodically used to fix or float the price differential between product prices at one market location versus another. Options are used to establish a floor price, a ceiling price, or a floor and a ceiling price (collar) for expected future oil and natural-gas sales. Derivative instruments are also used to manage commodity-price risk inherent in customer price requirements and to fix margins on the future sale of natural gas and NGLs from the Company's leased storage facilities (Marketing and Trading Derivative Activities).

Interest-rate swaps are used to fix or float interest rates on existing or anticipated indebtedness. The purpose of these instruments is to manage the Company's existing or anticipated exposure to interest-rate changes. The fair value of the Company's current interest-rate swap portfolio is subject to changes in interest rates.

The Company does not apply hedge accounting to any of its derivative instruments. As a result, gains and losses associated with derivative instruments are recognized currently in earnings. Net derivative losses attributable to derivatives previously subject to hedge accounting reside in accumulated other comprehensive income (loss) and are reclassified to earnings as the transactions to which the derivatives relate are recognized in earnings. See *Note 15-Accumulated Other Comprehensive Income (Loss)*.

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ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

6. Derivative Instruments (Continued)

Oil and Natural-Gas Production/Processing Derivative Activities The oil prices listed below are a combination of New York Mercantile Exchange (NYMEX) West Texas Intermediate and Intercontinental Exchange, Inc. (ICE) Brent Blend prices. The natural-gas prices listed below are NYMEX Henry Hub prices. The NGLs prices listed below are Oil Price Information Services prices. The following is a summary of the Company's derivative instruments related to oil and natural-gas production/processing derivative activities at June 30, 2016:

	2016 Settlement	2017 Settlement	2018 Settlement
Oil			
Three-Way Collars (MBbls/d)	83	-	-
Average price per barrel			
Ceiling sold price (call)	$ 63.82	$ -	$ -
Floor purchased price (put)	$ 54.46	$ -	$ -
Floor sold price (put)	$ 42.77	$ -	$ -
Natural Gas			
Three-Way Collars (thousand MMBtu/d)	-	682	250
Average price per MMBtu			
Ceiling sold price (call)	$ -	$ 3.60	$ 3.54
Floor purchased price (put)	$ -	$ 2.75	$ 2.75
Floor sold price (put)	$ -	$ 2.00	$ 2.00
Fixed-Price Contracts (thousand MMBtu/d)	14	32	-
Average price per MMBtu	$ 2.38	$ 3.14	$ -
NGLs			
Fixed-Price Contracts (MBbls/d)	-	2	-
Average price per barrel	$ -	$ 15.84	$ -

MBbls/d-thousand barrels per day
MMBtu/d-million British thermal units per day
MMBtu-million British thermal units

A three-way collar is a combination of three options: a sold call, a purchased put, and a sold put. The sold call establishes the maximum price that the Company will receive for the contracted commodity volumes. The purchased put establishes the minimum price that the Company will receive for the contracted volumes unless the market price for the commodity falls below the sold put strike price, at which point the minimum price equals the reference price (e.g., NYMEX) plus the excess of the purchased put strike price over the sold put strike price.

Marketing and Trading Derivative Activities The Company had financial derivative transactions with notional volumes of natural gas totaling 5 billion cubic feet (Bcf) at June 30, 2016, and 8 Bcf at December 31, 2015, that were entered into to mitigate commodity-price risk related to fixed-price purchase and sales contracts and storage activity.

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6. Derivative Instruments (Continued)

Interest-Rate Derivatives Anadarko has outstanding interest-rate swap contracts to manage interest-rate risk associated with anticipated debt issuances. The Company has locked in a fixed interest rate in exchange for a floating interest rate indexed to the three-month London Interbank Offered Rate (LIBOR). In February 2016, in exchange for amended terms with certain counterparties, the Company modified the mandatory termination dates from 2021 to 2018 and, in some cases, the related fixed interest rates on interest-rate swaps with an aggregate notional principal amount of $500 million. Additionally, an interest-rate swap agreement was settled in March 2016, resulting in a cash payment of $193 million.

At June 30, 2016, the Company had outstanding interest-rate swaps with a notional amount of $1.7 billion due prior to or at September 2021 that will manage interest-rate risk associated with the potential refinancing of the Company's $900 million Senior Notes due 2019 and the Zero-Coupon Senior Notes due 2036 (Zero Coupons), should the Zero Coupons be put to the Company prior to the swap termination dates. At the next put date in October 2016, the accreted value of the Zero Coupons will be $839 million. See *Note 8-Debt and Interest Expense*. Depending on market conditions, liability-management actions, or other factors, the Company may enter into offsetting interest-rate swap positions, or settle or amend, certain or all of the currently outstanding interest-rate swaps.

Derivative settlements and collateralization are classified as cash flows from operating activities unless the derivatives contain an other-than-insignificant financing element, in which case the settlements and collateralization are classified as cash flows from financing activities. As a result of prior extensions of reference-period start dates without settlement of the related interest-rate derivative obligations, the interest-rate derivatives in the Company's portfolio contain an other-than-insignificant financing element, and therefore, any settlements or collateralization related to these extended interest-rate derivatives are classified as cash flows from financing activities.

The Company had the following outstanding interest-rate swaps at June 30, 2016:

millions except percentages **Notional Principal Amount**		**Reference Period**	**Mandatory Termination Date**	**Weighted-Average Interest Rate**
$	50	September 2016 - 2026	September 2016	5.910%
$	50	September 2016 - 2046	September 2016	6.290%
$	500	September 2016 - 2046	September 2018	6.559%
$	300	September 2016 - 2046	September 2020	6.509%
$	450	September 2017 - 2047	September 2018	6.445%
$	100	September 2017 - 2047	September 2020	6.891%
$	250	September 2017 - 2047	September 2021	6.570%

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6. Derivative Instruments (Continued)

Effect of Derivative Instruments-Balance Sheet The following summarizes the fair value of the Company's derivative instruments:

millions	Gross Derivative Assets		Gross Derivative Liabilities	
Balance Sheet Classification	**June 30, 2016**	December 31, 2015	**June 30, 2016**	December 31, 2015
Commodity derivatives				
Other current assets	**$ 111**	$ 462	**$ (29)**	$ (177)
Other assets	**10**	8	**-**	-
Accrued expenses	**4**	-	**(30)**	(3)
Other liabilities	**2**	-	**(15)**	-
	127	470	**(74)**	(180)
Interest-rate derivatives				
Other current assets	**3**	2	**-**	-
Other assets	**15**	54	**-**	-
Accrued expenses	**-**	-	**(99)**	(54)
Other liabilities	**-**	-	**(1,749)**	(1,488)
	18	56	**(1,848)**	(1,542)
Total derivatives	**$ 145**	$ 526	**$ (1,922)**	$ (1,722)

Effect of Derivative Instruments-Statement of Income The following summarizes gains and losses related to derivative instruments:

millions	Three Months Ended June 30,		Six Months Ended June 30,	
Classification of (Gain) Loss Recognized	**2016**	2015	**2016**	2015
Commodity derivatives				
Gathering, processing, and marketing sales [1]	**$ 4**	$ 1	**$ 6**	$ 1
(Gains) losses on derivatives, net	**94**	1	**66**	(52)
Interest-rate derivatives				
(Gains) losses on derivatives, net	**213**	(312)	**538**	(107)
Total (gains) losses on derivatives, net	**$ 311**	$ (310)	**$ 610**	$ (158)

(1) Represents the effect of Marketing and Trading Derivative Activities.

6. Derivative Instruments (Continued)

Credit-Risk Considerations The financial integrity of exchange-traded contracts, which are subject to nominal credit risk, is assured by NYMEX or ICE through systems of financial safeguards and transaction guarantees. Over-the-counter traded swaps, options, and futures contracts expose the Company to counterparty credit risk. The Company monitors the creditworthiness of its counterparties, establishes credit limits according to the Company's credit policies and guidelines, and assesses the impact on the fair value of its counterparties' creditworthiness. The Company has the ability to require cash collateral or letters of credit to mitigate its credit-risk exposure.

The Company has netting agreements with financial institutions that permit net settlement of gross commodity derivative assets against gross commodity derivative liabilities, and routinely exercises its contractual right to offset gains and losses when settling with derivative counterparties. In addition, the Company has setoff agreements with certain financial institutions that may be exercised in the event of default and provide for contract termination and net settlement across derivative types. At June 30, 2016, $100 million of the Company's $1.922 billion gross derivative liability balance, and at December 31, 2015, $347 million of the Company's $1.722 billion gross derivative liability balance, would have been eligible for setoff against the Company's gross derivative asset balance in the event of default. Other than in the event of default, the Company does not net settle across derivative types.

The Company's derivative instruments are subject to individually negotiated credit provisions that may require collateral of cash or letters of credit depending on the derivative's portfolio valuation versus negotiated credit thresholds. These credit thresholds may also require full or partial collateralization or immediate settlement of the Company's obligations if certain credit-risk-related provisions are triggered, such as if the Company's credit rating from major credit rating agencies declines to a level that is below investment grade. In February 2016, Moody's Investors Service (Moody's) downgraded the Company's long-term debt credit rating from "Baa2" to "Ba1," which is below investment grade. The downgrade triggered credit-risk-related features with certain derivative counterparties and required the Company to post collateral under its derivative instruments. The amount of cash posted as collateral pursuant to the contractual requirements applicable to derivative instruments with financial institutions was $599 million at June 30, 2016, and $58 million at December 31, 2015. No counterparties have requested termination or full settlement of derivative positions. The aggregate fair value of derivative instruments with credit-risk-related contingent features for which a net liability position existed was $1.3 billion (net of collateral) at each of June 30, 2016, and December 31, 2015.

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6. Derivative Instruments (Continued)

Fair Value Fair value of futures contracts is based on unadjusted quoted prices in active markets for identical assets or liabilities, which represent Level 1 inputs. Valuations of physical-delivery purchase and sale agreements, over-the-counter financial swaps, and commodity option collars are based on similar transactions observable in active markets and industry-standard models that primarily rely on market-observable inputs. Inputs used to estimate fair value in industry-standard models are categorized as Level 2 inputs because substantially all assumptions and inputs are observable in active markets throughout the full term of the instruments. Inputs used to estimate the fair value of swaps and options include market-price curves; contract terms and prices; credit-risk adjustments; and, for Black-Scholes option valuations, discount factors and implied market volatility.

The following summarizes the fair value of the Company's derivative assets and liabilities by input level within the fair-value hierarchy:

millions

June 30, 2016	Level 1	Level 2	Level 3	Netting (1)	Collateral	Total
Assets						
Commodity derivatives	$ 1	$ 126	$ -	$ (35)	$ -	$ 92
Interest-rate derivatives	-	18	-	-	-	18
Total derivative assets	$ 1	$ 144	$ -	$ (35)	$ -	$ 110
Liabilities						
Commodity derivatives	$ (4)	$ (70)	$ -	$ 35	$ 5	$ (34)
Interest-rate derivatives	-	(1,848)	-	-	592	(1,256)
Total derivative liabilities	$ (4)	$ (1,918)	$ -	$ 35	$ 597	$ (1,290)
December 31, 2015						
Assets						
Commodity derivatives	$ 10	$ 460	$ -	$ (178)	$ (8)	$ 284
Interest-rate derivatives	-	56	-	-	-	56
Total derivative assets	$ 10	$ 516	$ -	$ (178)	$ (8)	$ 340
Liabilities						
Commodity derivatives	$ (1)	$ (179)	$ -	$ 178	$ -	$ (2)
Interest-rate derivatives	-	(1,542)	-	-	58	(1,484)
Total derivative liabilities	$ (1)	$ (1,721)	$ -	$ 178	$ 58	$ (1,486)

(1) Represents the impact of netting commodity derivative assets and liabilities with counterparties where the Company has the contractual right and intends to net settle.

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7. Tangible Equity Units

In June 2015, the Company issued 9.2 million 7.50% tangible equity units (TEUs) at a stated amount of $50.00 per TEU for net proceeds of $445 million. Each TEU is comprised of a prepaid equity purchase contract for common units of WGP and a senior amortizing note. Subsequent to issuance, each TEU may be legally separated into the two components. The prepaid equity purchase contract is considered a freestanding financial instrument, indexed to WGP common units, and meets the conditions for equity classification. The prepaid equity purchase contracts are included in noncontrolling interests, net of issuance costs, and the senior amortizing notes are included in short-term debt and long-term debt on the Company's Consolidated Balance Sheets.

Equity Component Unless settled earlier at the holder's option, each purchase contract has a mandatory settlement date of June 7, 2018. Anadarko has a right to elect to issue and deliver shares of Anadarko Petroleum Corporation common stock (APC shares) in lieu of delivering WGP common units at settlement. The Company will deliver not more than 0.8591 WGP common units and not less than 0.7159 WGP common units (or a computed number of APC shares) per TEU on the settlement date, subject to adjustment, at the settlement rate based upon the applicable market value of WGP common units (or APC shares).

Debt Component Each senior amortizing note has an initial principal amount of $10.95 and bears interest at 1.50% per year. On September 7, 2015, Anadarko began paying equal quarterly cash installments of $0.9375 per amortizing note (except for the September 7, 2015 installment payment, which was $0.9063 per amortizing note). The payments constitute a payment of interest and partial repayment of principal, with the aggregate per-year payments of principal and interest equating to a 7.50% cash payment with respect to each TEU. The senior amortizing notes have a final installment payment date of June 7, 2018, and are senior unsecured obligations of the Company.

8. Debt and Interest Expense

Debt Activity The following summarizes the Company's debt activity, after eliminating the effect of intercompany transactions, during the six months ended June 30, 2016:

	Carrying Value				
millions	**WES**	**WGP (1)**	**Anadarko (2)**	**Anadarko Consolidated**	**Description**
Balance at December 31, 2015	$ 2,691	$ -	$ 12,957	$ 15,648	
Issuances	-	-	794	794	4.850% Senior Notes due 2021
	-	-	1,088	1,088	5.550% Senior Notes due 2026
	-	-	1,088	1,088	6.600% Senior Notes due 2046
Borrowings	-	-	1,750	1,750	364-Day Facility
	530	-	-	530	WES RCF
	-	28	-	28	WGP RCF
Repayments	-	-	(1,749)	(1,749)	5.950% Senior Notes due 2016
	-	-	(1,245)	(1,245)	6.375% Senior Notes due 2017
	-	-	(1,750)	(1,750)	364-Day Facility
	(290)	-	-	(290)	WES RCF
	-	-	(250)	(250)	Commercial paper notes, net
	-	-	(17)	(17)	TEUs - senior amortizing notes
Other, net	1	-	27	28	Amortization of discounts, premiums, and debt issuance costs
Balance at June 30, 2016	$ 2,932	$ 28	$ 12,693	$ 15,653	

(1) Excludes WES.
(2) Excludes WES and WGP.

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8. Debt and Interest Expense (Continued)

Debt The Company's outstanding debt, excluding the capital lease obligation and any borrowings under the WGP revolving credit facility, is senior unsecured. The following summarizes the Company's outstanding debt after eliminating the effect of intercompany transactions:

millions	WES	WGP (1)	Anadarko (2)	Anadarko Consolidated
June 30, 2016				
Total borrowings at face value	**$ 2,960**	**$ 28**	**$ 14,325**	**$ 17,313**
Net unamortized discounts, premiums, and debt issuance costs (3)	**(28)**	**-**	**(1,632)**	**(1,660)**
Total borrowings	**2,932**	**28**	**12,693**	**15,653**
Capital lease obligation	**-**	**-**	**20**	**20**
Less short-term debt	**-**	**-**	**32**	**32**
Total long-term debt	**$ 2,932**	**$ 28**	**$ 12,681**	**$ 15,641**
December 31, 2015				
Total borrowings at face value	$ 2,720	$ -	$ 14,592	$ 17,312
Net unamortized discounts, premiums, and debt issuance costs (3)	(29)	-	(1,635)	(1,664)
Total borrowings	2,691	-	12,957	15,648
Capital lease obligation	-	-	20	20
Less short-term debt	-	-	32	32
Total long-term debt	$ 2,691	$ -	$ 12,945	$ 15,636

(1) Excludes WES.
(2) Excludes WES and WGP.
(3) Unamortized discounts, premiums, and debt issuance costs are amortized over the term of the related debt. Debt issuance costs related to revolving credit facilities are included in other current assets and other assets on the Company's Consolidated Balance Sheets.

During the second quarter of 2016, the Company used proceeds from its $3.0 billion March 2016 Senior Notes issuances to purchase and retire $1.250 billion of its $2.0 billion 6.375% Senior Notes due September 2017 pursuant to a tender offer and to redeem its $1.750 billion 5.950% Senior Notes due September 2016. The Company recognized a loss of $124 million for the early retirement and redemption of these senior notes, which included $114 million of premiums paid.
Anadarko's Zero Coupons can be put to the Company in October of each year, in whole or in part, for the then-accreted value, which will be $839 million at the next put date in October 2016. Anadarko's Zero Coupons were classified as long-term debt on the Company's Consolidated Balance Sheet at June 30, 2016, as the Company has the ability and intent to refinance these obligations using long-term debt, should the put be exercised.

Fair Value The Company uses a market approach to determine the fair value of its fixed-rate debt using observable market data, which results in a Level 2 fair-value measurement. The carrying amount of floating-rate debt approximates fair value as the interest rates are variable and reflective of market rates. The estimated fair value of the Company's total borrowings was $17.2 billion at June 30, 2016, and $15.7 billion at December 31, 2015.

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8. Debt and Interest Expense (Continued)

Anadarko Revolving Credit Facilities and Commercial Paper Program Anadarko has a $3.0 billion five-year senior unsecured revolving credit facility maturing in January 2021 (Five-Year Facility). In addition, in January 2016 the Company replaced its previous $2.0 billion 364-day senior unsecured revolving credit facility with a new $2.0 billion 364-day senior unsecured revolving credit facility (364-Day Facility), on identical terms, that will mature in January 2017. At June 30, 2016, the Company had no outstanding borrowings under the Five-Year Facility or the 364-Day Facility and was in compliance with all related covenants.

In January 2015, the Company initiated a commercial paper program, which allows for a maximum of $3.0 billion of unsecured commercial paper notes and is supported by the Five-Year Facility. The maturities of the commercial paper notes may vary, but may not exceed 397 days. In February 2016, Moody's downgraded the Company's commercial paper program credit rating, which essentially eliminated the Company's access to the commercial paper market. As a result, the Company has not issued commercial paper notes since the downgrade. At June 30, 2016, the Company had no outstanding borrowings under the commercial paper program.

WES and WGP Borrowings WES has a five-year $1.2 billion senior unsecured revolving credit facility maturing in February 2019 (WES RCF), which is expandable to $1.5 billion. At June 30, 2016, WES had outstanding borrowings under its RCF of $540 million at an interest rate of 1.77%, had outstanding letters of credit of $5 million, and had available borrowing capacity of $655 million. At June 30, 2016, WES was in compliance with all related covenants.

In March 2016, WGP entered into a three-year $250 million senior secured revolving credit facility maturing in March 2019 (WGP RCF), which is expandable to $500 million, subject to receiving increased or new commitments from lenders and the satisfaction of certain other conditions. Obligations under the WGP RCF are secured by a first priority lien on all of WGP's assets (not including the consolidated assets of WES), as well as all equity interests owned by WGP. Borrowings under the WGP RCF bear interest at LIBOR (with a floor of 0%), plus applicable margins ranging from 2.00% to 2.75% depending on WGP's consolidated leverage ratio, or at a base rate equal to the greatest of (i) the prime rate, (ii) the federal funds rate plus 0.50%, or (iii) LIBOR plus 1.00%, in each case plus applicable margins ranging from 1.00% to 1.75% based upon WGP's consolidated leverage ratio. At June 30, 2016, WGP had outstanding borrowings under its RCF of $28 million at an interest rate of 2.72%, had available borrowing capacity of $222 million, and was in compliance with all related covenants.

In July 2016, WES completed a public offering of $500 million aggregate principal amount of 4.650% Senior Notes due July 2026. Net proceeds were used to repay a portion of the amount outstanding under the WES RCF.

Interest Expense The following summarizes interest expense:

	Three Months Ended June 30,		Six Months Ended June 30,	
millions	**2016**	2015	**2016**	2015
Debt and other	$ **259**	$ 244	$ **517**	$ 498
Capitalized interest	**(42)**	(43)	**(80)**	(81)
Total interest expense	$ **217**	$ 201	$ **437**	$ 417

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9. Income Taxes

The following summarizes income tax expense (benefit) and effective tax rates:

	Three Months Ended June 30,		Six Months Ended June 30,	
millions except percentages	**2016**	2015	**2016**	2015
Income tax expense (benefit)	**$ (314)**	$ 77	**$ (697)**	$ (1,315)
Income (loss) before income taxes	**(925)**	185	**(2,306)**	(4,443)
Effective tax rate	**34%**	42%	**30%**	30%

The Company reported a loss before income taxes for the three and six months ended June 30, 2016, and the six months ended June 30, 2015. As a result, items that ordinarily increase or decrease the tax rate will have the opposite effect. The variance from the 35% U.S. federal statutory rate for the three and six months ended June 30, 2016 and 2015, was primarily attributable to the non-deductible Algerian exceptional profits tax for Algerian income tax purposes and the tax impact from foreign operations. In addition, the decrease from the 35% U.S. federal statutory rate for the three and six months ended June 30, 2016, was attributable to non-deductible goodwill related to divestitures and net changes in uncertain tax positions.

At June 30, 2016, the Company's Consolidated Balance Sheet included a $192 million tax receivable included in accounts receivable-others.

10. Conveyance of Future Hard Minerals Royalty Revenues

During the first quarter of 2016, the Company conveyed a limited-term nonparticipating royalty interest in certain of its coal and trona leases to a third party for $413 million, net of transaction costs. Such conveyance entitles the third party to receive up to $553 million in future royalty revenue over a period of not less than 10 years and not greater than 15 years. Additionally, such third party is entitled to receive 3% of the aggregate royalties earned during the first 10 years between $800 million and $900 million and 4% of the aggregate royalties earned during the first 10 years that exceed $900 million. Generally, such third party relies solely on the royalty payments to recover its investment and, as such, has the risk of the royalties not being sufficient to recover its investment over the term of the conveyance.

Proceeds from this transaction have been accounted for as deferred revenues and are included in accrued expenses and other long-term liabilities on the Company's Consolidated Balance Sheet. The deferred revenues will be amortized to other revenues, included in gains (losses) on divestitures and other, net on a unit-of-revenue basis over the term of the agreement. During the six months ended June 30, 2016, the Company amortized $19 million of deferred revenues as a result of this agreement. Proceeds from the transaction and payments to the third party are reported in financing activities in the Company's Consolidated Statement of Cash Flows.

The Company will make the first payment for royalties in September 2016. The specified future amounts that the Company expects to pay and the payment timing are subject to change based upon the actual royalties received by the Company during the term of the conveyance. The following summarizes the future amounts, prior to the 3% to 4% of any excess described above, that the Company expects to pay:

millions	
2016	$ 25
2017	50
2018	50
2019	52
2020	56
Later years	320
Total	$ 553

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11. Contingencies

Litigation The following is a discussion of any material developments in previously reported contingencies and any other material matters that have arisen since the filing of the Company's Annual Report on Form 10-K for the year ended December 31, 2015.

Deepwater Horizon Events In April 2010, the Macondo well in the Gulf of Mexico blew out and an explosion occurred on the *Deepwater Horizon* drilling rig, resulting in an oil spill. The well was operated by BP Exploration and Production Inc. (BP) and Anadarko held a 25% nonoperated interest. In October 2011, the Company and BP entered into a settlement agreement relating to the Deepwater Horizon events (Settlement Agreement). Pursuant to the Settlement Agreement, the Company is fully indemnified by BP against all claims and damages arising under the Oil Pollution Act of 1990 (OPA), claims for natural resource damages (NRD) and assessment costs, and any claims arising under the Operating Agreement with BP.
Numerous Deepwater Horizon event-related civil lawsuits were filed against BP and other parties, including the Company. Generally, the plaintiffs sought actual damages, punitive damages, declaratory judgment, and/or injunctive relief. This litigation was consolidated into a federal Multidistrict Litigation (MDL) action pending before Judge Carl Barbier in the U.S. District Court for the Eastern District of Louisiana in New Orleans, Louisiana (Louisiana District Court).

BP Consent Decree In July 2015, BP announced a settlement agreement in principle with the U.S. Department of Justice (DOJ) and certain states and local government entities regarding essentially all of the outstanding claims against BP related to the Deepwater Horizon event (BP Settlement) and, in October 2015, lodged a proposed consent decree with the Louisiana District Court. In April 2016, the Louisiana District Court approved the consent decree. As a result of the BP Settlement and approval of the consent decree, all liability relating to OPA-related environmental costs was resolved and all NRD claims and claims by the United States and the Gulf states impacted by the event relating to the MDL action were dismissed. For any remaining claims relating to the MDL action, the Company is fully indemnified by BP against any losses pursuant to the Settlement Agreement. For additional disclosure related to the Deepwater Horizon events, see *Note 15-Contingencies-Deepwater Horizon Events* in the *Notes to Consolidated Financial Statements* included in the Company's Annual Report on Form 10-K for the year ended December 31, 2015.

Penalties and Fines In December 2010, the DOJ, on behalf of the United States, filed a civil lawsuit in the Louisiana District Court against several parties, including the Company, seeking an assessment of civil penalties under the Clean Water Act (CWA) in an amount to be determined by the Louisiana District Court. After previously finding that Anadarko, as a nonoperating investor in the Macondo well, was not culpable with respect to the Deepwater Horizon events, the Louisiana District Court found Anadarko liable for civil penalties under Section 311 of the CWA as a working-interest owner in the Macondo well and entered a judgment of $159.5 million in December 2015. Neither party appealed the decision and the Company paid the penalty in the first quarter of 2016.

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12. Restructuring Charges

In the first quarter of 2016, the Company initiated a workforce reduction program to align the size and composition of Anadarko's workforce with the Company's expected future operating and capital plans. Employee notifications related to the workforce reduction program were completed by June 30, 2016. All restructuring charges will be recognized in 2016, with the exception of approximately $10 million of expense for retirement benefits expected to be recognized in the first quarter of 2017. The following summarizes the total expected restructuring charges and the amounts expensed during the three and six months ended June 30, 2016, which are included in general and administrative expenses in the Company's Consolidated Statements of Income:

millions	Total Expected Costs	Three Months Ended June 30, 2016	Six Months Ended June 30, 2016
Costs by category			
Cash severance	$ 153	$ 15	$ 146
Retirement benefits [1]	220	27	76
Share-based compensation	34	6	29
Total	$ 407	$ 48	$ 251

(1) Includes termination benefits, curtailments, and settlements. See *Note 13-Pension Plans and Other Postretirement Benefits*.

The following summarizes the changes in the cash severance-related liability included in accounts payable on the Company's Consolidated Balance Sheet:

millions	2016
Balance at January 1	$ -
Accruals	146
Payments	(126)
Balance at June 30	$ 20

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13. Pension Plans and Other Postretirement Benefits

The Company has contributory and non-contributory defined-benefit pension plans, which include both qualified and supplemental plans. The Company also provides certain health care and life insurance benefits for certain retired employees. Retiree health care benefits are funded by contributions from the retiree and, in certain circumstances, contributions from the Company. The Company's retiree life insurance plan is noncontributory. The following summarizes the Company's pension and other postretirement benefit cost:

	Pension Benefits		Other Benefits	
millions	**2016**	2015	**2016**	2015
Three Months Ended June 30				
Service cost	**$ 23**	$ 29	**$ -**	$ 2
Interest cost	**23**	26	**3**	4
Expected return on plan assets	**(24)**	(28)	**-**	-
Amortization of net actuarial loss (gain)	**10**	13	**-**	-
Amortization of net prior service cost (credit)	**-**	-	**(6)**	1
Settlement expense	**24**	-	**-**	-
Curtailment expense	**-**	-	**3**	-
Net periodic benefit cost	**$ 56**	$ 40	**$ -**	$ 7
Six Months Ended June 30				
Service cost	**$ 49**	$ 59	**$ 1**	$ 5
Interest cost	**49**	51	**6**	8
Expected return on plan assets	**(51)**	(55)	**-**	-
Amortization of net actuarial loss (gain)	**18**	26	**-**	-
Amortization of net prior service cost (credit)	**-**	-	**(12)**	1
Settlement expense	**24**	-	**-**	-
Termination benefits expense	**44**	-	**-**	-
Curtailment expense	**8**	-	**-**	-
Net periodic benefit cost	**$ 141**	$ 81	**$ (5)**	$ 14

The Company's workforce reduction program resulted in remeasurements of its pension and other postretirement benefit obligations during 2016. The remeasurements resulted in increases in the benefit obligation of $171 million for the pension benefit plans and $23 million for the other postretirement benefit plans, with a corresponding decrease in other comprehensive income.
At December 31, 2015, total expected contributions related to unfunded pension plans were $25 million for 2016. The Company expects to contribute an additional $82 million in 2016 and $23 million in 2017 to unfunded pension plans primarily related to the workforce reduction program. See *Note 12-Restructuring Charges*.

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14. Stockholders' Equity

The Company's basic earnings per share (EPS) is computed based on the average number of shares of common stock outstanding for the period and includes the effect of any participating securities and TEUs as appropriate. Diluted EPS includes the effect of the Company's outstanding stock options, restricted stock awards, restricted stock units, TEUs, and WES Series A Preferred units, if the inclusion of these items is dilutive.
The following provides a reconciliation between basic and diluted earnings per share attributable to common stockholders:

	Three Months Ended June 30,		Six Months Ended June 30,	
millions except per-share amounts	**2016**	2015	**2016**	2015
Net income (loss)				
Net income (loss) attributable to common stockholders	**$ (692)**	$ 61	**$ (1,726)**	$ (3,207)
Income (loss) effect of TEUs	**(2)**	-	**(3)**	-
Less distributions on participating securities	**-**	1	**-**	2
Basic	**$ (694)**	$ 60	**$ (1,729)**	$ (3,209)
Income (loss) effect of TEUs	**(1)**	-	**(1)**	-
Diluted	**$ (695)**	$ 60	**$ (1,730)**	$ (3,209)
Shares				
Average number of common shares outstanding-basic	**510**	508	**510**	507
Dilutive effect of stock options	**-**	1	**-**	-
Average number of common shares outstanding-diluted	**510**	509	**510**	507
Excluded due to anti-dilutive effect	**11**	6	**10**	11
Net income (loss) per common share				
Basic	**$ (1.36)**	$ 0.12	**$ (3.39)**	$ (6.32)
Diluted	**$ (1.36)**	$ 0.12	**$ (3.39)**	$ (6.32)

15. Accumulated Other Comprehensive Income (Loss)

The following summarizes the after-tax changes in the balances of accumulated other comprehensive income (loss):

millions	Interest-rate Derivatives Previously Subject to Hedge Accounting	Pension and Other Postretirement Plans	Total
Balance at December 31, 2015	$ (42)	$ (341)	$ (383)
Other comprehensive income (loss), before reclassifications	**-**	**(120)**	**(120)**
Reclassifications to Consolidated Statement of Income	**3**	**13**	**16**
Balance at June 30, 2016	**$ (39)**	**$ (448)**	**$ (487)**

16. Noncontrolling Interests

WES, a publicly traded consolidated subsidiary, is a limited partnership formed by Anadarko to acquire, own, develop, and operate midstream assets. During the first quarter of 2016, WES issued 14 million Series A Preferred units to private investors for net proceeds of $440 million, and issued 1.3 million common units to the Company. Proceeds from these issuances were used to acquire interests in Springfield Pipeline LLC from the Company. During the second quarter of 2016, WES issued an additional eight million Series A Preferred units to private investors, pursuant to the full exercise of an option granted in connection with the initial issuance, and raised net proceeds of $247 million.

Class C units issued to Anadarko will receive quarterly distributions in the form of additional Class C units until the end of 2017, unless WES elects to convert the units to common units earlier or Anadarko elects to extend the conversion date. WES distributed 534 thousand Class C units to Anadarko during the six months ended June 30, 2016, and 498 thousand Class C units to Anadarko during 2015. During 2015, WES issued approximately 874 thousand common units to the public for net proceeds of $57 million.

WGP, a publicly traded consolidated subsidiary, is a limited partnership formed by Anadarko to own partnership interests in WES. During the three months ended June 30, 2016, Anadarko sold 12.5 million of its WGP common units to the public for net proceeds of $476 million. At June 30, 2016, Anadarko's ownership interest in WGP consisted of an 81.6% limited partner interest and the entire non-economic general partner interest. The remaining 18.4% limited partner interest in WGP was owned by the public.

At June 30, 2016, WGP's ownership interest in WES consisted of a 30.0% limited partner interest, the entire 1.5% general partner interest, and all of the WES incentive distribution rights. At June 30, 2016, Anadarko also owned an 8.4% limited partner interest in WES through other subsidiaries' ownership of common and Class C units. The remaining 60.1% limited partner interest in WES was owned by the public.

17. Variable Interest Entities

Consolidated VIEs The Company determined that the partners in WGP and WES with equity at risk lack the power, through voting rights or similar rights, to direct the activities that most significantly impact WGP's and WES's economic performance; therefore, WGP and WES are considered VIEs. Anadarko, through its ownership of the general partner interest in WGP, has the power to direct the activities that most significantly affect economic performance and the obligation to absorb losses or the right to receive benefits that could be potentially significant to WGP and WES, therefore Anadarko is considered the primary beneficiary and consolidates WGP and WES. See *Note 16-Noncontrolling Interests* for additional information on WGP and WES.

Assets and Liabilities of VIEs The assets of WGP and WES cannot be used by Anadarko for general corporate purposes and are both included in and disclosed parenthetically on the Company's Consolidated Balance Sheets. The carrying amounts of liabilities related to WGP and WES for which the creditors do not have recourse to other assets of the Company are both included in and disclosed parenthetically on the Company's Consolidated Balance Sheets.

All outstanding debt for WES at June 30, 2016, and December 31, 2015, including any borrowings under the WES RCF, is recourse to WES's general partner, which in turn has been indemnified in certain circumstances by certain wholly owned subsidiaries of the Company for such liabilities. All outstanding debt for WGP at June 30, 2016, and December 31, 2015, including any borrowings under the WGP RCF, is recourse to WGP's general partner, which is a wholly owned subsidiary of the Company. See *Note 8-Debt and Interest Expense* for additional information on WGP and WES long-term debt balances.

VIE Financing WGP's sources of liquidity include borrowings under its RCF and distributions from WES. WES's sources of liquidity include cash and cash equivalents, cash flows generated from operations, interest income from a note receivable from Anadarko as discussed below, borrowings under its RCF, the issuance of additional partnership units, or debt offerings. See *Note 8-Debt and Interest Expense* and *Note 16-Noncontrolling Interests* for additional information on WGP and WES financing activity.

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17. Variable Interest Entities (Continued)

Financial Support Provided to VIEs Concurrent with the closing of its May 2008 initial public offering, WES loaned the Company $260 million in exchange for a 30-year note bearing interest at a fixed annual rate of 6.50%, payable quarterly. The related interest income for WES was $4 million for each of the three months ended June 30, 2016 and 2015, and $8 million for each of the six months ended June 30, 2016 and 2015. The note receivable and related interest income are eliminated in consolidation.

In March 2015, WES acquired the Company's interest in Delaware Basin JV Gathering LLC. The acquisition was financed using a deferred purchase price obligation which requires a cash payment from WES to the Company due on March 31, 2020. The net present value of this obligation was $29 million at June 30, 2016, and $189 million at December 31, 2015.

In order to reduce WES's exposure to a majority of the commodity-price risk inherent in certain of their contracts, Anadarko has commodity price swap agreements in place with WES expiring in 2016. WES has recorded a capital contribution from Anadarko in its Consolidated Statement of Equity and Partners' Capital for the amount by which the swap price exceeds the applicable market price. WES recorded a $16 million capital contribution from Anadarko for the six months ended June 30, 2016, and a capital contribution of zero for the six months ended June 30, 2015.

18. Supplemental Cash Flow Information

The following summarizes cash paid (received) for interest and income taxes, as well as non-cash investing and financing activities:

	Six Months Ended June 30,	
millions	**2016**	2015
Cash paid (received)		
Interest, net of amounts capitalized (1)	**$ 427**	$ 1,621
Income taxes, net of refunds (2)	**(883)**	6
Non-cash investing activities		
Fair value of properties and equipment from non-cash transactions	**$ 3**	$ 126
Asset retirement cost additions	**49**	90
Accruals of property, plant, and equipment	**505**	901
Net liabilities assumed (divested) in acquisitions and divestitures	**(36)**	(29)
Non-cash investing and financing activities		
Floating production, storage, and offloading vessel construction period obligation	**$ 11**	$ 43

(1) Includes $1.2 billion of interest related to the Tronox settlement payment in 2015.
(2) Includes $881 million from a tax refund related to the income tax benefit associated with the Company's 2015 tax net operating loss carryback.

19. Segment Information

Anadarko's business segments are separately managed due to distinct operational differences and unique technology, distribution, and marketing requirements. The Company's three reporting segments are oil and gas exploration and production, midstream, and marketing. The oil and gas exploration and production segment explores for and produces oil, condensate, natural gas, and NGLs and plans for the development and operation of the Company's LNG project in Mozambique. The midstream segment engages in gathering, processing, treating, and transporting Anadarko and third-party oil, condensate, natural-gas, and NGLs production. The midstream reporting segment consists of two operating segments, WES and other midstream, which are aggregated into one reporting segment due to similar financial and operating characteristics. The marketing segment sells much of Anadarko's oil, condensate, natural-gas, and NGLs production as well as third-party purchased volumes.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

19. Segment Information (Continued)

To assess the performance of Anadarko's operating segments, the chief operating decision maker analyzes Adjusted EBITDAX. The Company defines Adjusted EBITDAX as income (loss) before income taxes; gains (losses) on divestitures, net; exploration expense; depreciation, depletion, and amortization (DD&A); impairments; interest expense; total (gains) losses on derivatives, net, less net cash from settlement of commodity derivatives; and certain items not related to the Company's normal operations, less net income (loss) attributable to noncontrolling interests. During the periods presented, items not related to the Company's normal operations included restructuring charges related to the workforce reduction program included in general and administrative expenses, Deepwater Horizon settlement and related costs included in other operating expenses, loss on early extinguishment of debt, Tronox-related contingent loss, and certain other nonoperating items included in other (income) expense, net. The Company's definition of Adjusted EBITDAX excludes gains (losses) on divestitures, net and exploration expense as they are not indicators of operating efficiency for a given reporting period. However, exploration expense is monitored by management as part of costs incurred in exploration and development activities. Similarly, DD&A and impairments are excluded from Adjusted EBITDAX as a measure of segment operating performance because capital expenditures are evaluated at the time capital costs are incurred. Adjusted EBITDAX also excludes interest expense to allow for assessment of segment operating results without regard to Anadarko's financing methods or capital structure. Total (gains) losses on derivatives, net, less net cash from settlement of commodity derivatives are excluded from Adjusted EBITDAX because these (gains) losses are not considered a measure of asset operating performance. Finally, net income (loss) attributable to noncontrolling interests is excluded from the Company's measure of Adjusted EBITDAX because it represents earnings that are not attributable to the Company's common stockholders.
Management believes that the presentation of Adjusted EBITDAX provides information useful in assessing the Company's financial condition and results of operations and that Adjusted EBITDAX is a widely accepted financial indicator of a company's ability to incur and service debt, fund capital expenditures, and make distributions to stockholders. Adjusted EBITDAX as defined by Anadarko may not be comparable to similarly titled measures used by other companies and should be considered in conjunction with net income (loss) attributable to common stockholders and other performance measures, such as operating income or cash flows from operating activities.
Below is a reconciliation of consolidated Adjusted EBITDAX to income (loss) before income taxes:

	Three Months Ended June 30,		**Six Months Ended June 30,**	
millions	**2016**	2015	**2016**	2015
Income (loss) before income taxes	**$ (925)**	$ 185	**$ (2,306)**	$ (4,443)
(Gains) losses on divestitures, net	**104**	91	**102**	425
Exploration expense	**76**	103	**202**	1,186
DD&A	**984**	1,214	**2,133**	2,470
Impairments	**18**	30	**34**	2,813
Interest expense	**217**	201	**437**	417
Total (gains) losses on derivatives, net, less net cash from settlement of commodity derivatives	**371**	(229)	**775**	14
Restructuring charges	**48**	-	**251**	-
Other operating expense	**-**	-	**1**	4
Loss on early extinguishment of debt	**124**	-	**124**	-
Tronox-related contingent loss	**-**	-	**-**	5
Certain other nonoperating items	**(56)**	-	**(56)**	22
Less net income (loss) attributable to noncontrolling interests	**81**	47	**117**	79
Consolidated Adjusted EBITDAX	**$ 880**	$ 1,548	**$ 1,580**	$ 2,834

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ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

19. Segment Information (Continued)

Information presented below as "Other and Intersegment Eliminations" includes corporate costs, results from hard-minerals royalties, and net cash from settlement of commodity derivatives. The following summarizes selected financial information for Anadarko's reporting segments:

millions	Oil and Gas Exploration & Production	Midstream	Marketing	Other and Intersegment Eliminations	Total
Three Months Ended June 30, 2016					
Sales revenues	**$ 1,033**	**$ 141**	**$ 811**	**$ -**	**$ 1,985**
Intersegment revenues	**567**	**340**	**(676)**	**(231)**	**-**
Other	**-**	**-**	**-**	**34**	**34**
Total revenues and other [1]	**1,600**	**481**	**135**	**(197)**	**2,019**
Operating costs and expenses [2]	**790**	**219**	**177**	**(65)**	**1,121**
Net cash from settlement of commodity derivatives	**-**	**-**	**-**	**(60)**	**(60)**
Other (income) expense, net [3]	**-**	**-**	**-**	**1**	**1**
Net income (loss) attributable to noncontrolling interests	**-**	**81**	**-**	**-**	**81**
Total expenses and other	**790**	**300**	**177**	**(124)**	**1,143**
Total (gains) losses on derivatives, net included in marketing revenue, less net cash from settlement	**-**	**-**	**4**	**-**	**4**
Adjusted EBITDAX	**$ 810**	**$ 181**	**$ (38)**	**$ (73)**	**$ 880**
Three Months Ended June 30, 2015					
Sales revenues	$ 1,356	$ 191	$ 1,090	$ -	$ 2,637
Intersegment revenues	885	303	(954)	(234)	-
Other	-	-	-	90	90
Total revenues and other [1]	2,241	494	136	(144)	2,727
Operating costs and expenses [2]	832	234	192	(59)	1,199
Net cash from settlement of commodity derivatives	-	-	-	(82)	(82)
Other (income) expense, net	-	-	-	15	15
Net income (loss) attributable to noncontrolling interests	-	47	-	-	47
Total expenses and other	832	281	192	(126)	1,179
Adjusted EBITDAX	$ 1,409	$ 213	$ (56)	$ (18)	$ 1,548

(1) Total revenues and other excludes gains (losses) on divestitures, net since these gains and losses are excluded from Adjusted EBITDAX.
(2) Operating costs and expenses excludes exploration expense, DD&A, impairments, restructuring charges, and other operating expense since these expenses are excluded from Adjusted EBITDAX.
(3) Other (income) expense, net excludes certain other nonoperating items since these items are excluded from Adjusted EBITDAX.

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ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

19. Segment Information (Continued)

millions	Oil and Gas Exploration & Production	Midstream	Marketing	Other and Intersegment Eliminations	Total
Six Months Ended June 30, 2016					
Sales revenues	$ 1,744	$ 266	$ 1,609	$ -	$ 3,619
Intersegment revenues	1,168	642	(1,339)	(471)	-
Other	-	-	-	72	72
Total revenues and other (1)	2,912	908	270	(399)	3,691
Operating costs and expenses (2)	1,563	402	353	(154)	2,164
Net cash from settlement of commodity derivatives	-	-	-	(163)	(163)
Other (income) expense, net (3)	-	-	-	1	1
Net income (loss) attributable to noncontrolling interests	-	117	-	-	117
Total expenses and other	1,563	519	353	(316)	2,119
Total (gains) losses on derivatives, net included in marketing revenue, less net cash from settlement	-	-	8	-	8
Adjusted EBITDAX	$ 1,349	$ 389	$ (75)	$ (83)	$ 1,580
Six Months Ended June 30, 2015					
Sales revenues	$ 2,426	$ 365	$ 2,431	$ -	$ 5,222
Intersegment revenues	2,002	605	(2,145)	(462)	-
Other	-	-	-	160	160
Total revenues and other (1)	4,428	970	286	(302)	5,382
Operating costs and expenses (2)	1,834	474	390	(96)	2,602
Net cash from settlement of commodity derivatives	-	-	-	(172)	(172)
Other (income) expense, net (3)	-	-	-	40	40
Net income (loss) attributable to noncontrolling interests	-	79	-	-	79
Total expenses and other	1,834	553	390	(228)	2,549
Total (gains) losses on derivatives, net included in marketing revenue, less net cash from settlement	-	-	1	-	1
Adjusted EBITDAX	$ 2,594	$ 417	$ (103)	$ (74)	$ 2,834

(1) Total revenues and other excludes gains (losses) on divestitures, net since these gains and losses are excluded from Adjusted EBITDAX.
(2) Operating costs and expenses excludes exploration expense, DD&A, impairments, restructuring charges, and other operating expense since these expenses are excluded from Adjusted EBITDAX.
(3) Other (income) expense, net excludes certain other nonoperating items since these items are excluded from Adjusted EBITDAX.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Unless the context otherwise requires, the terms "Anadarko" and "Company" refer to Anadarko Petroleum Corporation and its consolidated subsidiaries. The Company has made in this Form 10-Q, and may from time to time make in other public filings, press releases, and management discussions, forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, concerning the Company's operations, economic performance, and financial condition. These forward-looking statements include, among other things, information concerning future production and reserves, schedules, plans, timing of development, contributions from oil and gas properties, marketing and midstream activities, and also include those statements preceded by, followed by, or that otherwise include the words "may," "could," "believes," "expects," "anticipates," "intends," "estimates," "projects," "target," "goal," "plans," "objective," "should," "would," "will," "potential," "continue," "forecast," "future," "likely," "outlook," or similar expressions or variations on such expressions. For such statements, the Company claims the protection of the safe harbor for forward-looking statements contained in the Private Securities Litigation Reform Act of 1995. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, it can give no assurance that such expectations will be realized. Anadarko undertakes no obligation to publicly update or revise any forward-looking statements whether as a result of new information, future events, or otherwise.

These forward-looking statements involve risk and uncertainties. Important factors that could cause actual results to differ materially from the Company's expectations include, but are not limited to, the following risks and uncertainties:

- *the Company's assumptions about energy markets*
- *production and sales volume levels*
- *levels of oil, natural-gas, and natural-gas liquids (NGLs) reserves*
- *operating results*
- *competitive conditions*
- *technology*
- *availability of capital resources, levels of capital expenditures, and other contractual obligations*
- *supply and demand for, the price of, and the commercialization and transporting of oil, natural gas, NGLs, and other products or services*
- *volatility in the commodity-futures market*
- *weather*
- *inflation*
- *availability of goods and services, including unexpected changes in costs*
- *drilling risks*
- *processing volumes and pipeline throughput*
- *general economic conditions, nationally, internationally, or in the jurisdictions in which the Company is, or in the future may be, doing business*
- *the Company's inability to timely obtain or maintain permits or other governmental approvals, including those necessary for drilling and/or development projects*
- *legislative or regulatory changes, including changes relating to hydraulic fracturing; retroactive royalty or production tax regimes; deepwater drilling and permitting regulations; derivatives reform; changes in state, federal, and foreign income taxes; environmental regulation; environmental risks; and liability under federal, state, foreign, and local environmental laws and regulations*
- *civil or political unrest or acts of terrorism in a region or country*
- *the creditworthiness and performance of the Company's counterparties, including financial institutions, operating partners, and other parties*

- *volatility in the securities, capital, or credit markets and related risks such as general credit, liquidity, and interest-rate risk*
- *the Company's ability to successfully monetize select assets, repay or refinance its debt, and the impact of changes in the Company's credit ratings*
- *disruptions in international oil, NGLs, and condensate cargo shipping activities*
- *physical, digital, internal, and external security breaches*
- *supply and demand, technological, political, governmental, and commercial conditions associated with long-term development and production projects in domestic and international locations*
- *other factors discussed below and elsewhere in "Risk Factors" and in "Management's Discussion and Analysis of Financial Condition and Results of Operations-Critical Accounting Estimates" included in the Company's Annual Report on Form 10-K for the year ended December 31, 2015, this Form 10-Q, and in the Company's other public filings, press releases, and discussions with Company management*

The following discussion should be read together with the *Consolidated Financial Statements* and the *Notes to Consolidated Financial Statements*, which are included in this Form 10-Q in Part I, Item 1; the information set forth in the *Risk Factors* under Part II, Item 1A; the *Consolidated Financial Statements* and the *Notes to Consolidated Financial Statements,* which are included in Part II, Item 8 of the Company's Annual Report on Form 10-K for the year ended December 31, 2015; and the information set forth in the *Risk Factors* under Part I, Item 1A of the Company's Annual Report on Form 10-K for the year ended December 31, 2015.

OUTLOOK

During 2015, the oil and natural-gas industry experienced a significant decrease in commodity prices driven by a global supply/demand imbalance for oil and an oversupply of natural gas in the United States. Low commodity prices have continued into 2016 and may exist for an extended period. The Company's revenues, operating results, cash flows from operations, capital spending, and future growth rates are highly dependent on the global commodity-price markets, which affect the value the Company receives from its sales of oil, natural gas, and NGLs.

The Company has continued its disciplined and focused approach in 2016 by emphasizing value over growth, preserving and building value through capital allocation, enhancing operational efficiencies, and continuing an active monetization program. In the first quarter of 2016, the Company initiated a workforce reduction program to align the size and composition of Anadarko's workforce with the Company's expected future operating and capital plans. Employee notifications related to the workforce reduction program were completed by June 30, 2016. All of the $407 million of expected restructuring charges will be recognized in 2016, with the exception of approximately $10 million of expense for retirement benefits expected to be recognized in the first quarter of 2017.

The Company estimates a 2016 capital spending range of $3.1 billion to $3.3 billion, including approximately $450 million to $490 million for Western Gas Partners, LP (WES), a publicly traded consolidated subsidiary, excluding any acquisitions made by WES. The Company has currently allocated approximately 65% of its 2016 capital spending budget to development activities, 15% to exploration activities, and 20% to gathering and processing activities and other business activities. The Company currently expects its 2016 capital spending by area to be approximately 40% for the U.S. onshore region and Alaska, 20% for the Gulf of Mexico, 20% for Midstream and other (including WES), and 20% for International.

The Company will continue to evaluate the oil and natural-gas price environments and may adjust its capital spending plans to maintain the appropriate liquidity and financial flexibility. Anadarko expects that its 2016 capital expenditures will be within its cash flows from operations and asset monetizations. As of June 30, 2016, the Company closed monetizations totaling $2.5 billion in 2016, including asset divestitures, the sale of Anadarko's interest in Springfield Pipeline LLC to WES, the sale of 12.5 million of the Company's common units in Western Gas Equity Partners, LP (WGP) to the public, and the Company's conveyance of a limited-term nonparticipating royalty interest in certain of its coal and trona leases to a third party. These monetizations continue Anadarko's track record of actively managing its portfolio and reaffirm the Company's commitment toward strengthening its balance sheet.

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Liquidity As of June 30, 2016, Anadarko had $1.4 billion of cash on hand plus $5.0 billion of borrowing capacity under its revolving credit facilities.

Anadarko believes that its cash on hand, anticipated operating cash flows, and proceeds from expected future asset monetizations will be sufficient to fund the Company's projected 2016 operational and capital programs. In response to the current commodity price environment, the Board of Directors (Board) decreased the quarterly dividend from $0.27 per share to $0.05 per share in February 2016. On an annualized basis, the dividend decrease and the workforce reduction program (without consideration for restructuring charges) are expected to have the effect of providing approximately $800 million of available cash to enhance the Company's operations and financial flexibility. During the second quarter of 2016, the Company used proceeds from its $3.0 billion March 2016 Senior Notes issuances to purchase and retire $1.250 billion of its $2.0 billion 6.375% Senior Notes due September 2017 pursuant to a tender offer and to redeem its $1.750 billion 5.950% Senior Notes due September 2016. Also during the second quarter of 2016, Anadarko received cash of $881 million from a tax refund related to the income tax benefit associated with the Company's 2015 tax net operating loss carryback and sold 12.5 million of its common units in WGP to the public for net proceeds of $476 million. Further, Anadarko enters into strategic derivative positions to reduce commodity-price risk and increase the predictability of cash flows. At June 30, 2016, derivative positions covered 26% of Anadarko's anticipated oil sales volumes and 1% of its anticipated natural-gas sales volumes for 2016, 41% of its anticipated natural-gas sales volumes and 2% of its anticipated NGLs sales volumes for 2017, and 14% of anticipated natural-gas sales volumes for 2018. These instruments had a fair value of $45 million as of June 30, 2016. See *Note 6-Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q. Anadarko believes that the actions taken to enhance the Company's liquidity position coupled with its asset portfolio and operating and financial performance provide the necessary financial flexibility to fund the Company's current and long-term operations.

Potential for Future Impairments The Company did not recognize any material impairments during the six months ended June 30, 2016, although it is reasonably possible that prolonged low or further declines in commodity prices, changes to the Company's drilling plans in response to lower prices, or increases in drilling or operating costs could result in future property impairments.

OVERVIEW

Anadarko is among the world's largest independent exploration and production companies. Anadarko is engaged in the exploration, development, production, and marketing of oil, condensate, natural gas, and NGLs, and in the marketing of anticipated production of liquefied natural gas. The Company also engages in the gathering, processing, treating, and transporting of oil, condensate, natural gas, and NGLs. The Company has exploration and production activities in various countries around the world, including activities in the United States, Algeria, Ghana, Mozambique, Colombia, Côte d'Ivoire, New Zealand, Kenya, and other countries.

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Significant operating and financial activities for the second quarter of 2016 include the following:

Overall

- Anadarko's second-quarter sales volumes averaged 792 thousand barrels of oil equivalent per day (MBOE/d), representing a 6% decrease from the second quarter of 2015, primarily due to a decrease in natural-gas and oil and condensate sales volumes.
- The Company recognized workforce reduction program expenses of $48 million in the second quarter for a total of $251 million for the six months ended June 30, 2016. Total program expenses are expected to be $407 million.
- The Company closed $2.5 billion of monetizations year to date, including proceeds received during the quarter from asset divestitures and the sale of a portion of the Company's WGP common units to the public.

U.S. Onshore

- Second-quarter liquids sales volumes averaged 291 thousand barrels per day (MBbls/d), representing a 5% decrease from the second quarter of 2015, primarily due to a natural production decline in the Eagleford shale and reduced capital activity in the Wattenberg field.
- Second-quarter natural-gas sales volumes averaged 353 MBOE/d, representing a 6% decrease from the second quarter of 2015, primarily due to the September 2015 sale of certain coalbed methane properties in the Rockies, the July 2015 sale of certain U.S. onshore properties in East Texas, and natural production declines at Greater Natural Buttes. These decreases were partially offset by improved well performance in the Wattenberg field and the injection of volumes into storage in 2015.

Gulf of Mexico

- Second-quarter sales volumes averaged 74 MBOE/d, representing an 11% decrease from the second quarter of 2015, primarily due to a decrease in natural-gas sales volumes as a result of the last producing well going off line at Independence Hub (IHUB) in December 2015.
- The Shenandoah-5 appraisal well (33% working interest) encountered more than 1,040 net feet of oil pay, extending the eastern limits of the field.

International

- Second-quarter sales volumes averaged 74 MBbls/d, representing an 11% decrease from the second quarter of 2015, primarily in Ghana due to downtime related to a maintenance issue with the floating, production, storage, and offloading unit (FPSO) turret bearing.

Financial

- Anadarko's net loss attributable to common stockholders for the second quarter of 2016 totaled $692 million.
- The Company generated $1.2 billion of cash flow from operations and ended the quarter with $1.4 billion of cash on hand.
- In April 2016, WES issued an additional eight million Series A Preferred units to private investors, pursuant to the full exercise of an option granted in connection with the initial March 2016 issuance, for net proceeds of $247 million.
- The Company used proceeds from its $3.0 billion March 2016 Senior Notes issuances to purchase and retire $1.250 billion of its $2.0 billion 6.375% Senior Notes due September 2017 pursuant to a tender offer and to redeem its $1.750 billion 5.950% Senior Notes due September 2016. The Company recognized a loss of $124 million for the early retirement and redemption of these senior notes, which included $114 million of premiums paid.
- In July 2016, WES completed a public offering of $500 million aggregate principal amount of 4.650% Senior Notes due July 2026.

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FINANCIAL RESULTS

millions except per-share amounts	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Oil and condensate, natural-gas, and NGLs sales	**$ 1,680**	$ 2,332	**$ 3,074**	$ 4,624
Gathering, processing, and marketing sales	**305**	305	**545**	598
Gains (losses) on divestitures and other, net	**(70)**	(1)	**(30)**	(265)
Revenues and other	**1,915**	2,636	**3,589**	4,957
Costs and expenses	**2,247**	2,546	**4,785**	9,075
Other (income) expense	**593**	(95)	**1,110**	325
Income tax expense (benefit)	**(314)**	77	**(697)**	(1,315)
Net income (loss) attributable to common stockholders	**$ (692)**	$ 61	**$ (1,726)**	$ (3,207)
Net income (loss) per common share attributable to common stockholders-diluted	**$ (1.36)**	$ 0.12	**$ (3.39)**	$ (6.32)
Average number of common shares outstanding-diluted	**510**	509	**510**	507

The following discussion pertains to Anadarko's results of operations, financial condition, and changes in financial condition. Any increases or decreases "for the three months ended June 30, 2016," refer to the comparison of the three months ended June 30, 2016, to the three months ended June 30, 2015, and any increases or decreases "for the six months ended June 30, 2016," refer to the comparison of the six months ended June 30, 2016, to the six months ended June 30, 2015. The primary factors that affect the Company's results of operations include commodity prices for oil, natural gas, and NGLs; sales volumes; the cost of finding such reserves; and operating costs.

Revenues and Sales Volumes

millions except percentages	Three Months Ended June 30, Oil and Condensate	Natural Gas	NGLs	Total
2015 sales revenues	$ 1,616	$ 487	$ 229	$ 2,332
Changes associated with sales volumes	**(114)**	**(34)**	**(7)**	**(155)**
Changes associated with prices	**(377)**	**(133)**	**13**	**(497)**
2016 sales revenues	**$ 1,125**	**$ 320**	**$ 235**	**$ 1,680**
Increase (decrease) vs. 2015	**(30)%**	**(34)%**	**3%**	**(28)%**

millions except percentages	Six Months Ended June 30, Oil and Condensate	Natural Gas	NGLs	Total
2015 sales revenues	$ 3,035	$ 1,128	$ 461	$ 4,624
Changes associated with sales volumes	**(178)**	**(127)**	**(30)**	**(335)**
Changes associated with prices	**(882)**	**(315)**	**(18)**	**(1,215)**
2016 sales revenues	**$ 1,975**	**$ 686**	**$ 413**	**$ 3,074**
Increase (decrease) vs. 2015	**(35)%**	**(39)%**	**(10)%**	**(34)%**

Changes associated with sales volumes for the three and six months ended June 30, 2016, include decreases associated with asset divestitures.

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The following provides Anadarko's sales volumes for the three and six months ended June 30:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	Inc (Dec) vs. 2015	2015	**2016**	Inc (Dec) vs. 2015	2015
Barrels of Oil Equivalent						
(MMBOE except percentages)						
United States	**65**	(6)%	69	**132**	(8)%	144
International	**7**	(11)	8	**15**	(13)	17
Total barrels of oil equivalent	**72**	(6)	77	**147**	(9)	161
Barrels of Oil Equivalent per Day						
(MBOE/d except percentages)						
United States	**718**	(6)%	762	**728**	(8)%	796
International	**74**	(11)	84	**81**	(13)	94
Total barrels of oil equivalent per day	**792**	(6)	846	**809**	(9)	890

MMBOE-million barrels of oil equivalent

Sales volumes represent actual production volumes adjusted for changes in commodity inventories and natural-gas production volumes provided to satisfy a commitment established in conjunction with the Jubilee development plan in Ghana. Anadarko employs marketing strategies to minimize market-related shut-ins, maximize realized prices, and manage credit-risk exposure. For additional information, see *Note 6-Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q and *Other (Income) Expense-(Gains) Losses on Derivatives, net*. Production of oil, natural gas, and NGLs is usually not affected by seasonal swings in demand.

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Oil and Condensate Sales Volumes, Average Prices, and Revenues

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	Inc (Dec) vs. 2015	2015	**2016**	Inc (Dec) vs. 2015	2015
United States						
Sales volumes-MMBbls	**20**	(5)%	21	**41**	(3)%	43
MBbls/d	**227**	(5)	240	**229**	(3)	238
Price per barrel	**$ 40.25**	(26)	$ 54.14	**$ 34.07**	(31)	$ 49.23
International						
Sales volumes-MMBbls	**6**	(12)%	8	**14**	(13)%	16
MBbls/d	**69**	(12)	78	**76**	(13)	88
Price per barrel	**$ 46.75**	(23)	$ 60.81	**$ 39.84**	(30)	$ 57.12
Total						
Sales volumes-MMBbls	**26**	(7)%	29	**55**	(6)%	59
MBbls/d	**296**	(7)	318	**305**	(6)	326
Price per barrel	**$ 41.77**	(25)	$ 55.78	**$ 35.51**	(31)	$ 51.37
Oil and condensate sales revenues *(millions)*	**$ 1,125**	(30)	$ 1,616	**$ 1,975**	(35)	$ 3,035

MMBbls-million barrels

Anadarko's oil and condensate sales volumes decreased by 22 MBbls/d for the three months ended June 30, 2016, and 21 MBbls/d for the six months ended June 30, 2016.

- Sales volumes in the Rockies decreased by 9 MBbls/d for the three months ended June 30, 2016, and 13 MBbls/d for the six months ended June 30, 2016, primarily due to reduced capital activity in the Wattenberg field. Sales volumes for the six months ended June 30, 2016, also decreased as a result of the April 2015 sale of certain enhanced oil recovery (EOR) assets.
- International sales volumes decreased by 9 MBbls/d for the three months ended June 30, 2016, and 12 MBbls/d for the six months ended June 30, 2016, primarily in Ghana due to downtime to address new production and offtake procedures resulting from a maintenance issue with the FPSO turret bearing. The partnership has determined a long-term solution to convert the FPSO to a permanently moored facility and is expecting the work program to be complete in the first half of 2017. In the meantime, shuttle tankers continue to successfully conduct offtakes. Sales volumes for the six months ended June 30, 2016, also decreased as a result of the timing of liftings in Ghana.
- Sales volumes in the Southern and Appalachia Region decreased by 6 MBbls/d for the three months ended June 30, 2016, and 4 MBbls/d for the six months ended June 30, 2016, primarily due to a natural production decline in the Eagleford shale, partially offset by higher sales volumes due to continued development in the Delaware basin.
- Sales volumes in the Gulf of Mexico were relatively flat for the three months ended June 30, 2016, and increased by 5 MBbls/d for the six months ended June 30, 2016, primarily from the Lucius development, which achieved first oil in the first quarter of 2015.

Anadarko's average oil price received decreased for the three and six months ended June 30, 2016, primarily due to continued global oversupply and concerns of slowing oil demand growth.

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Natural-Gas Sales Volumes, Average Prices, and Revenues

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	Inc (Dec) vs. 2015	2015	**2016**	Inc (Dec) vs. 2015	2015
United States						
Sales volumes-Bcf	**199**	(7)%	215	**409**	(11)%	461
MMcf/d	**2,188**	(7)	2,354	**2,245**	(11)	2,545
Price per Mcf	**$ 1.61**	(29)	$ 2.28	**$ 1.68**	(31)	$ 2.45
Natural-gas sales revenues *(millions)*	**$ 320**	(34)	$ 487	**$ 686**	(39)	$ 1,128

Bcf-billion cubic feet
MMcf/d-million cubic feet per day
Mcf-thousand cubic feet

The Company's natural-gas sales volumes decreased by 166 MMcf/d for the three months ended June 30, 2016, and 300 MMcf/d for the six months ended June 30, 2016.

- Sales volumes in the Rockies decreased by 150 MMcf/d for the three months ended June 30, 2016, and 161 MMcf/d for the six months ended June 30, 2016, primarily due to the September 2015 sale of certain coalbed methane properties and a natural production decline at Greater Natural Buttes, partially offset by higher 2016 sales volumes in the Wattenberg field as a result of improved well performance.
- Sales volumes in the Gulf of Mexico decreased by 40 MMcf/d for the three months ended June 30, 2016, and 89 MMcf/d for the six months ended June 30, 2016, primarily as a result of the last producing well going off line at IHUB in December 2015.
- Sales volumes in the Southern and Appalachia Region increased by 24 MMcf/d for the three months ended June 30, 2016, primarily due to the injection of volumes into storage in 2015, third-party infrastructure downtime in the Marcellus shale in 2015, and continued development in the Delaware basin. The increase for the three months ended June 30, 2016, was partially offset by decreased sales volumes in 2016 as a result of the July 2015 sale of certain U.S. onshore properties in East Texas and a natural production decline in the Eagleford shale. Sales volumes for the six months ended June 30, 2016, decreased by 50 MMcf/d, primarily due to the decreases discussed above, partially offset by higher 2016 sales volumes in the Delaware basin due to continued development.

The average natural-gas price Anadarko received decreased for the three and six months ended June 30, 2016, primarily due to lower weather-driven residential and commercial demand, which have contributed to sustained high gas storage levels.

Natural-Gas Liquids Sales Volumes, Average Prices, and Revenues

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	Inc (Dec) vs. 2015	2015	**2016**	Inc (Dec) vs. 2015	2015
Total						
Sales volumes-MMBbls	**13**	(3)%	12	**24**	(7)%	25
MBbls/d	**131**	(3)	136	**130**	(7)	140
Price per barrel	**$ 19.60**	6	$ 18.50	**$ 17.49**	(4)	$ 18.24
Natural-gas liquids sales revenues *(millions)*	**$ 235**	3	$ 229	**$ 413**	(10)	$ 461

NGLs sales represent revenues from the sale of product derived from the processing of Anadarko's natural-gas production. The Company's NGLs sales volumes decreased by 5 MBbls/d for the three months ended June 30, 2016, and by 10 MBbls/d for the six months ended June 30, 2016, primarily due to increased ethane rejection in the United States in 2016.

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Gathering, Processing, and Marketing

millions except percentages	Three Months Ended June 30, 2016	Inc (Dec) vs. 2015	2015	Six Months Ended June 30, 2016	Inc (Dec) vs. 2015	2015
Gathering, processing, and marketing sales	$ **305**	-%	$ 305	$ **545**	(9)%	$ 598
Gathering, processing, and marketing expense	**252**	(1)	255	**467**	(8)	509
Total gathering, processing, and marketing, net	$ **53**	6	$ 50	$ **78**	(12)	$ 89

Gathering and processing sales includes revenue from the sale of NGLs and remaining residue gas extracted from natural gas purchased from third parties and processed by Anadarko as well as fee revenue earned by providing gathering, processing, compression, and treating services to third parties. Marketing sales include the margin earned from purchasing and selling third-party oil and natural gas. Gathering, processing, and marketing expense includes the cost of third-party natural gas purchased and processed by Anadarko as well as other operating and transportation expenses related to the Company's costs to perform gathering, processing, and marketing activities. Gathering, processing, and marketing, net was relatively flat for the three months ended June 30, 2016, and decreased by $11 million for the six months ended June 30, 2016, primarily due to plant downtime in 2016 and the 2015 divestitures of certain midstream assets, partially offset by higher marketing margins.

Gains (Losses) on Divestitures and Other, net

millions except percentages	Three Months Ended June 30, 2016	Inc (Dec) vs. 2015	2015	Six Months Ended June 30, 2016	Inc (Dec) vs. 2015	2015
Gains (losses) on divestitures	$ **(104)**	(14)%	$ (91)	$ **(102)**	76%	$ (425)
Other	**34**	(62)	90	**72**	(55)	160
Total gains (losses) on divestitures and other, net	$ **(70)**	NM	$ (1)	$ **(30)**	89	$ (265)

NM-not meaningful

Gains (losses) on divestitures and other, net includes gains (losses) on divestitures and other operating revenues, including hard-minerals royalties, earnings from equity investments, and other revenues.

2016

- The Company recognized a loss of $53 million associated with the June divestiture of certain U.S. onshore assets in the Rockies for net proceeds of $593 million.
- The Company recognized a loss of $50 million on assets held for sale associated with the divestiture of certain U.S. onshore assets that is expected to close in the third quarter of 2016.

2015

- The Company recognized losses of $340 million associated with the April divestiture of certain EOR assets in the Rockies, with a sales price of $703 million, for net proceeds of $675 million.
- The Company recognized a loss of $97 million associated with the July divestiture of certain oil and gas properties and related midstream assets in East Texas, with a sales price of $440 million, for net proceeds of $425 million.
- The Company recognized income of $63 million during the three months ended June 30, 2015, and $117 million during the six months ended June 30, 2015, related to the settlement of a royalty lawsuit associated with a property in the Gulf of Mexico.

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Costs and Expenses

	Three Months Ended June 30,			Six Months Ended June 30,		
	2016	Inc (Dec) vs. 2015	2015	**2016**	Inc (Dec) vs. 2015	2015
Oil and gas operating *(millions)*	**$ 202**	(11)%	$ 226	**$ 410**	(21)%	$ 522
Oil and gas operating-per BOE	**2.80**	(4)	2.93	**2.78**	(14)	3.24
Oil and gas transportation *(millions)*	**246**	(13)	283	**488**	(17)	588
Oil and gas transportation-per BOE	**3.41**	(7)	3.67	**3.32**	(9)	3.65

BOE-barrel of oil equivalent

Oil and gas operating expense decreased by $24 million for the three months ended June 30, 2016, primarily as a result of divestitures in 2015. Oil and gas operating expense decreased by $112 million for the six months ended June 30, 2016, due to lower expenses of $56 million as a result of divestitures in 2015; lower workover costs of $31 million in Ghana, the Gulf of Mexico, and the Rockies; and lower nonoperated costs of $18 million across all areas. The related costs per BOE decreased by $0.13 for the three months ended June 30, 2016, and by $0.46 for the six months ended June 30, 2016.
Oil and gas transportation expense decreased by $37 million for the three months ended June 30, 2016, and $100 million for the six months ended June 30, 2016, due to lower sales volumes across all areas. The related costs per BOE decreased by $0.26 for the three months ended June 30, 2016, and by $0.33 for the six months ended June 30, 2016, due to lower costs as a result of decreased sales volumes.

	Three Months Ended June 30,		Six Months Ended June 30,	
millions	**2016**	2015	**2016**	2015
Exploration Expense				
Dry hole expense	**$ (5)**	$ 13	**$ 6**	$ 42
Impairments of unproved properties	**15**	18	**39**	998
Geological and geophysical expense	**32**	16	**69**	38
Exploration overhead and other	**34**	56	**88**	108
Total exploration expense	**$ 76**	$ 103	**$ 202**	$ 1,186

For the three months ended June 30, 2016, total exploration expense decreased by $27 million.

- Dry hole expense decreased by $18 million. The Company recognized $13 million in the second quarter of 2015 primarily associated with wells in the Rockies.
- Geological and geophysical expense increased by $16 million primarily due to seismic activities in Colombia in 2016.
- Exploration overhead and other decreased by $22 million primarily due to lower employee-related expenses in 2016.

For the six months ended June 30, 2016, total exploration expense decreased by $984 million.

- Dry hole expense decreased by $36 million. The Company recognized $42 million in 2015 primarily associated with wells in Mozambique.
- Impairments of unproved properties decreased by $959 million. The Company recognized a $935 million impairment in the first quarter of 2015 related to the Company's unproved Greater Natural Buttes properties as a result of lower commodity prices.
- Geological and geophysical expense increased by $31 million primarily due to seismic activities in Colombia in 2016.
- Exploration overhead and other decreased by $20 million primarily due to lower employee-related expenses in 2016.

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millions except percentages	Three Months Ended June 30, 2016	Inc (Dec) vs. 2015	2015	Six Months Ended June 30, 2016	Inc (Dec) vs. 2015	2015
General and administrative	**$ 305**	10%	$ 278	**$ 754**	29%	$ 585
Depreciation, depletion, and amortization	**984**	(19)	1,214	**2,133**	(14)	2,470
Other taxes	**157**	4	151	**274**	(18)	333
Impairments	**18**	(40)	30	**34**	(99)	2,813
Other operating expense	**7**	17	6	**23**	(67)	69

General and administrative expense (G&A) included $48 million of charges associated with the workforce reduction program for the three months ended June 30, 2016, and $251 million for the six months ended June 30, 2016. Excluding the workforce reduction expenses, G&A decreased by $21 million for the three months ended June 30, 2016, and by $82 million for the six months ended June 30, 2016, primarily due to lower employee-related expenses primarily associated with decreased benefit, bonus plan, and salary expenses. See *Note 12-Restructuring Charges* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

Depreciation, depletion, and amortization expense decreased by $230 million for the three months ended June 30, 2016, and by $337 million for the six months ended June 30, 2016, primarily due to the following:

- lower costs for U.S. onshore and midstream properties as a result of 2015 asset impairments
- lower 2016 sales volumes associated with U.S. onshore properties
- lower costs and sales volumes as a result of 2015 divestitures of certain gathering and processing facilities
- cost revisions related to certain asset retirement obligations associated with fully depreciated assets

Other taxes decreased by $59 million for the six months ended June 30, 2016, primarily due to lower ad valorem taxes of $36 million and lower Algerian exceptional profits taxes of $23 million. These decreases were primarily due to lower commodity prices and lower sales volumes.

Impairment expense for the six months ended June 30, 2015, included $2.3 billion related to the Company's Greater Natural Buttes oil and gas properties and $449 million for related midstream properties in the Rockies, which were impaired due to lower forecasted commodity prices.

Other operating expense decreased by $46 million for the six months ended June 30, 2016, primarily due to expenses in 2015 for the early termination of a drilling rig.

Other (Income) Expense

millions	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
Interest Expense				
Debt and other	**$ 259**	$ 244	**$ 517**	$ 498
Capitalized interest	**(42)**	(43)	**(80)**	(81)
Total interest expense	**$ 217**	$ 201	**$ 437**	$ 417

Interest expense increased by $16 million for the three months ended June 30, 2016, and by $20 million for the six months ended June 30, 2016, primarily due to the $3.0 billion March 2016 Senior Notes issuances.

	Three Months Ended June 30,		Six Months Ended June 30,	
millions	**2016**	2015	**2016**	2015
Loss on early extinguishment of debt	**$ 124**	$ -	**$ 124**	$ -

During the second quarter of 2016, the Company used proceeds from its $3.0 billion March 2016 Senior Notes issuances to purchase and retire $1.250 billion of its $2.0 billion 6.375% Senior Notes due September 2017 pursuant to a tender offer and to redeem its $1.750 billion 5.950% Senior Notes due September 2016. The Company recognized a loss of $124 million for the early retirement and redemption of these senior notes, which included $114 million of premiums paid.

	Three Months Ended June 30,		Six Months Ended June 30,	
millions	**2016**	2015	**2016**	2015
(Gains) Losses on Derivatives, net				
(Gains) losses on commodity derivatives, net	**$ 94**	$ 1	**$ 66**	$ (52)
(Gains) losses on interest-rate derivatives, net	**213**	(312)	**538**	(107)
Total (gains) losses on derivatives, net	**$ 307**	$ (311)	**$ 604**	$ (159)

(Gains) losses on derivatives, net represents the changes in fair value of the Company's derivative instruments as a result of changes in commodity prices and interest rates, contract modifications, and settlements. An interest-rate swap agreement was settled in March 2016, resulting in a cash payment of $193 million. The Company settled commodity derivatives resulting in cash receipts of $60 million for the three months ended June 30, 2016, $81 million for the three months ended June 30, 2015, $165 million for the six months ended June 30, 2016, and $172 million for the six months ended June 30, 2015.
For additional information, see <u>*Note 6-Derivative Instruments*</u> in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

	Three Months Ended June 30,		Six Months Ended June 30,	
millions	**2016**	2015	**2016**	2015
Other (Income) Expense, net				
Interest income	**$ (4)**	$ (2)	**$ (7)**	$ (7)
Other	**(51)**	17	**(48)**	69
Total other (income) expense, net	**$ (55)**	$ 15	**$ (55)**	$ 62

For the three months ended June 30, 2016, other income, net increased by $70 million.

- As a result of a Chapter 11 bankruptcy declaration by a third party, the U.S. Department of the Interior ordered Anadarko to perform the decommissioning of a production facility and related wells, previously sold to the third party. The Company accrued the costs to decommission the facility and wells in prior years. During the second quarter of 2016, the Company substantially completed the decommissioning of the wells. Final costs were lower than expected and the Company recognized income of $56 million as a result of the reduced obligation.

For the six months ended June 30, 2016, other income, net increased by $117 million.

- Other income, net increased by $78 million related to the decommissioning obligation mentioned above.
- Favorable changes in foreign currency gains/losses of $34 million were primarily associated with foreign currency held in escrow pending final determination of the Company's Brazilian tax liability attributable to the 2008 divestiture of the Peregrino field offshore Brazil.

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Income Tax Expense

millions except percentages	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Income tax expense (benefit)	**$ (314)**	$ 77	**$ (697)**	$ (1,315)
Income (loss) before income taxes	**(925)**	185	**(2,306)**	(4,443)
Effective tax rate	**34%**	42%	**30%**	30%

The Company reported a loss before income taxes for the three and six months ended June 30, 2016, and the six months ended June 30, 2015. As a result, items that ordinarily increase or decrease the tax rate will have the opposite effect. The variance from the 35% U.S. federal statutory rate for the three and six months ended June 30, 2016 and 2015, was primarily attributable to the non-deductible Algerian exceptional profits tax for Algerian income tax purposes and the tax impact from foreign operations. In addition, the decrease from the 35% U.S. federal statutory rate for the three and six months ended June 30, 2016, was attributable to non-deductible goodwill related to divestitures and net changes in uncertain tax positions.

Net Income (Loss) Attributable to Noncontrolling Interests

millions except percentages	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Net income (loss) attributable to noncontrolling interests	**$ 81**	$ 47	**$ 117**	$ 79
Public ownership in WES, limited partnership interest	**60.1%**	55.2%	**60.1%**	55.2%
Public ownership in WGP, limited partnership interest	**18.4%**	12.7%	**18.4%**	12.7%

See *Note 16-Noncontrolling Interests* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

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LIQUIDITY AND CAPITAL RESOURCES

	Six Months Ended June 30,	
millions	**2016**	2015
Net cash provided by (used in) operating activities	**$ 1,092**	$ (3,261)
Net cash provided by (used in) investing activities	**(965)**	(2,785)
Net cash provided by (used in) financing activities	**329**	849

Overview Anadarko believes that its cash on hand, anticipated operating cash flows, and proceeds from expected future asset monetizations will be sufficient to fund the Company's projected 2016 operational and capital programs. In addition, the Company has available borrowing capacity to supplement its working capital needs. The Company continuously monitors its liquidity needs and evaluates available funding alternatives in light of current and expected conditions. Anadarko has a variety of funding sources available, including cash on hand, an asset portfolio that provides ongoing cash-flow-generating capacity, opportunities for liquidity enhancement through divestitures and joint-venture arrangements that reduce future capital expenditures, and the Company's credit facilities. In addition, an effective registration statement is available to Anadarko covering the sale of WGP common units owned by the Company.

Effects of Moody's Credit Rating Downgrade In February 2016, Standard and Poor's affirmed Anadarko's "BBB" long-term debt credit rating and changed the outlook from stable to negative. Later in February 2016, Moody's Investors Service (Moody's) lowered the Company's long-term debt credit rating from "Baa2" to "Ba1," which is below investment grade. In March 2016, Fitch Ratings affirmed Anadarko's "BBB" long-term debt credit rating and changed the outlook from stable to negative.

As a result of Moody's downgrade of Anadarko's credit rating to a level that is below investment grade, the Company's credit thresholds with certain derivative counterparties were reduced and in some cases eliminated, which required the Company to increase the amount of collateral posted with derivative counterparties when the Company's net trading position is a liability in excess of the contractual threshold. No counterparties have requested termination or full settlement of derivative positions. The aggregate fair value of derivative instruments with credit-risk-related contingent features for which a net liability position existed was $1.3 billion (net of collateral) at each of June 30, 2016, and December 31, 2015. The amount of cash posted as collateral pursuant to the contractual requirements applicable to derivative instruments with financial institutions was $599 million at June 30, 2016, and $58 million at December 31, 2015.

The Moody's credit rating downgrade required Anadarko to post collateral in the form of letters of credit or cash as financial assurance of its performance under certain contractual arrangements such as pipeline transportation contracts and oil and gas sales contracts. The amount of letters of credit or cash provided as assurance of the Company's performance under these types of contractual arrangements with respect to credit-risk-related contingent features was $274 million at June 30, 2016, and zero at December 31, 2015.

Also in February 2016, Moody's downgraded Anadarko's commercial paper program credit rating, which essentially eliminated the Company's access to the commercial paper market. As a result, the Company has not issued commercial paper notes since the downgrade, but instead has used its 364-day senior unsecured revolving credit facility (364-Day Facility) for short-term working capital requirements, as needed.

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Operating Activities

One of the primary sources of variability in the Company's cash flows from operating activities is the fluctuation in commodity prices, the impact of which Anadarko partially mitigates by entering into commodity derivatives. Sales volume changes also impact cash flow, but historically have not been as volatile as commodity prices. Anadarko's cash flows from operating activities are also impacted by the costs related to operations and interest payments related to the Company's outstanding debt.
Anadarko generated $1.1 billion of cash from operating activities during the six months ended June 30, 2016, which included the $881 million tax refund related to the income tax benefit associated with the Company's 2015 tax net operating loss carryback, the $159.5 million payment of the Clean Water Act (CWA) penalty, and the payment of $182 million related to severance costs and retirement benefits in connection with the workforce reduction program. Cash used in operating activities for the same period of 2015 was $3.3 billion, which included the $5.2 billion Tronox settlement payment. Excluding the impact of the tax refund and payments for the CWA penalty, severance costs and retirement benefits, and the Tronox settlement, operating cash flows for the six months ended June 30, 2016, decreased by $1.4 billion primarily due to decreased sales revenues as a result of lower commodity prices.

Investing Activities

Capital Expenditures The following presents the Company's capital expenditures for the six months ended June 30:

millions	**2016**	2015
Cash Flows from Investing Activities		
Additions to properties and equipment and dry hole costs	**$ 1,879**	$ 3,501
Adjustments for capital expenditures		
Changes in capital accruals	**(249)**	(310)
Other	**(6)**	32
Total capital expenditures (1)	**$ 1,624**	$ 3,223

(1) Includes WES capital expenditures of $260 million for the six months ended June 30, 2016, and $278 million for the six months ended June 30, 2015.

The Company's capital expenditures decreased by $1.6 billion for the six months ended June 30, 2016, as reduced development and exploration activity resulted in the following:

- decreased development costs of $1.2 billion primarily in the Rockies and the Southern and Appalachia Region
- decreased exploration costs of $214 million primarily in Colombia and Mozambique
- decreased gathering, processing, and other costs of $154 million primarily due to lower expenditures for plants and gathering in the Rockies

Carried-Interest Arrangements In the third quarter of 2014, the Company entered into a carried-interest arrangement that requires a third party to fund $442 million of Anadarko's capital costs in exchange for a 34% working interest in the Eaglebine development, located in Southeast Texas. The third-party funding is expected to cover Anadarko's future capital costs in the development through 2020. At June 30, 2016, $141 million of the $442 million carry obligation had been funded.
In the second quarter of 2013, the Company entered into a carried-interest arrangement that requires a third party to fund $860 million of Anadarko's capital costs in exchange for a 12.75% working interest in the Heidelberg development, located in the Gulf of Mexico. At June 30, 2016, $853 million of the $860 million carry obligation had been funded.

Divestitures During the six months ended June 30, 2016, Anadarko received pretax sales proceeds related to property divestiture transactions of $900 million primarily related to the divestitures of certain U.S. onshore assets in the Rockies, East Texas/Louisiana, and West Texas. See *Note 3-Divestitures and Assets Held for Sale* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

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Investments During the six months ended June 30, 2016, the Company made capital contributions of $46 million for equity investments, which are included in other, net under Investing Activities in the Consolidated Statements of Cash Flows. These contributions were primarily associated with joint ventures for pipelines.

Financing Activities

millions except percentages		**June 30, 2016**		December 31, 2015
Total debt	$	**15,673**	$	15,668
Total equity		**14,600**		15,457
Debt to total capitalization ratio		**51.8%**		50.3%

Senior Notes The following summarizes the Company's debt activity related to senior notes for the six months ended June 30, 2016:

millions		**Face Value**	**Description**
Issuances	$	**800**	4.850% Senior Notes due 2021
		1,100	5.550% Senior Notes due 2026
		1,100	6.600% Senior Notes due 2046
Repayments		**(1,250)**	6.375% Senior Notes due 2017
		(1,750)	5.950% Senior Notes due 2016
		(17)	Tangible equity units (TEUs) - senior amortizing notes

During the second quarter of 2016, the Company used proceeds from its $3.0 billion March 2016 Senior Notes issuances to purchase and retire $1.250 billion of its $2.0 billion 6.375% Senior Notes due September 2017 pursuant to a tender offer and to redeem its $1.750 billion 5.950% Senior Notes due September 2016. The Company recognized a loss of $124 million for the early retirement and redemption of these senior notes, which included $114 million of premiums paid.

In July 2016, WES completed a public offering of $500 million aggregate principal amount of 4.650% Senior Notes due July 2026. Net proceeds were used to repay a portion of the amount outstanding under its five-year $1.2 billion senior unsecured revolving credit facility maturing in February 2019 (WES RCF).

Revolving Credit Facilities Anadarko has a $3.0 billion five-year senior unsecured revolving credit facility maturing in January 2021 (Five-Year Facility) and the 364-Day Facility that matures in January 2017.

WES has a $1.2 billion RCF, which is expandable to $1.5 billion. In March 2016, WGP entered into a three-year $250 million senior secured revolving credit facility maturing in March 2019 (WGP RCF), which is expandable to $500 million, subject to receiving increased or new commitments from lenders and the satisfaction of certain other conditions.

The following summarizes the Company's debt activity related to revolving credit facilities for the six months ended June 30, 2016:

millions		**2016**	**Description**
Borrowings	$	**1,750**	364-Day Facility
		530	WES RCF
		28	WGP RCF
Repayments		**(1,750)**	364-Day Facility
		(290)	WES RCF

Anadarko Credit Facilities During the six months ended June 30, 2016, borrowings under the 364-Day Facility were primarily used for general short-term working capital needs. At June 30, 2016, the Company had no outstanding borrowings under the Five-Year Facility or the 364-Day Facility.

WES and WGP Credit Facilities During the six months ended June 30, 2016, WES borrowings were primarily used for general corporate purposes, including the funding of a portion of its acquisition of Springfield Pipeline LLC and capital expenditures. At June 30, 2016, WES had outstanding borrowings under its RCF of $540 million at an interest rate of 1.77%, had outstanding letters of credit of $5 million, and had available borrowing capacity of $655 million.

During the six months ended June 30, 2016, WGP borrowings were used to fund the purchase of WES common units. At June 30, 2016, WGP had outstanding borrowings under its RCF of $28 million at an interest rate of 2.72% and had available borrowing capacity of $222 million.

For additional information on the revolving credit facilities, such as years of maturity, interest rates, and covenants, see *Note 8-Debt and Interest Expense* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

Commercial Paper Program The Company has a commercial paper program, which allows for a maximum of $3.0 billion of unsecured commercial paper notes and is supported by the Company's Five-Year Facility. As a result of Moody's downgrade of Anadarko's commercial paper program credit rating, the Company's access to the commercial paper market was essentially eliminated. The Company repaid $250 million of commercial paper notes during the first quarter of 2016, and at June 30, 2016, there were no outstanding borrowings under the commercial paper program. See *Note 8-Debt and Interest Expense* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q for additional information.

Debt Maturities Anadarko may from time to time seek to retire or purchase its outstanding debt through cash purchases and/or exchanges for other debt or equity securities in open market purchases, privately negotiated transactions, or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, the Company's liquidity requirements, contractual restrictions, and other factors. The amounts involved may be material.

At June 30, 2016, Anadarko's scheduled debt maturities during 2016 consisted of $17 million of senior amortizing notes associated with the TEUs. Anadarko's Zero-Coupon Senior Notes due 2036 (Zero Coupons) can be put to the Company in October of each year, in whole or in part, for the then-accreted value, which will be $839 million at the next put date in October 2016. The Company classified the Zero Coupons as long-term debt on the Company's Consolidated Balance Sheet at June 30, 2016, as Anadarko has the ability and intent to refinance these obligations using long-term debt, should the put be exercised. At June 30, 2016, Anadarko's scheduled debt maturities during 2017 consisted of $750 million of 6.375% Senior Notes due September 2017 and $34 million of senior amortizing notes associated with the TEUs.

For additional information on the Company's debt instruments, such as transactions during the period, years of maturity, and interest rates, see *Note 8-Debt and Interest Expense* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

Derivative Instruments The Company's derivative instruments are subject to individually negotiated credit provisions that may require collateral of cash or letters of credit depending on the derivatives portfolio valuation versus negotiated credit thresholds. These credit thresholds may also require full or partial collateralization or immediate settlement of the Company's obligations if certain credit-risk-related provisions are triggered, such as if the Company's credit rating from major credit rating agencies declines to a level that is below investment grade. Derivative settlements and collateralization are classified as cash flows from operating activities unless the derivatives contain an other-than-insignificant financing element, in which case the settlements and collateralization are classified as cash flows from financing activities. The amount of cash collateral provided by the Company on its interest-rate derivatives with an other-than-insignificant financing element pursuant to the contractual requirements applicable to derivative instruments with financial institutions was $592 million at June 30, 2016, and $58 million at December 31, 2015. Additionally, an interest-rate swap agreement was settled in March 2016, resulting in a cash payment of $193 million. At June 30, 2016, Anadarko expects additional net cash outlays of $52 million in 2016 related to interest-rate derivative settlements.

For additional information, see *Note 6-Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q and *Effects of Moody's Credit Rating Downgrade* above.

Conveyance of Future Hard Minerals Royalty Revenues During the first quarter of 2016, the Company conveyed a limited-term nonparticipating royalty interest in certain of its coal and trona leases to a third party for $413 million, net of transaction costs. For additional information, see *Note 10-Conveyance of Future Hard Minerals Royalty Revenues* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

Common Stock Dividends Anadarko paid dividends of $51 million to its common stockholders during the six months ended June 30, 2016, and $277 million during the six months ended June 30, 2015. In response to the current commodity-price environment, the Board decreased the Company's quarterly dividend from $0.27 per share to $0.05 per share in February 2016. Anadarko has paid a dividend to its common stockholders on a quarterly basis since becoming a public company in 1986.
The amount of future dividends paid to Anadarko common stockholders will be determined by the Board on a quarterly basis and is based on earnings, financial conditions, capital requirements, the effect a dividend payment would have on the Company's compliance with relevant financial covenants, and other factors deemed relevant by the Board.

Equity Transactions Anadarko sold 12.5 million of its WGP common units to the public for net proceeds of $476 million, which were used for general corporate purposes. WES has a continuous offering program, which allows the issuance of up to an aggregate of $500 million of WES common units. The remaining amount available to be issued under this program was $442 million at June 30, 2016. During the first quarter of 2016, WES issued 14 million Series A Preferred units to private investors for net proceeds of $440 million. During the second quarter of 2016, WES issued an additional eight million Series A Preferred units to private investors, pursuant to the full exercise of an option granted in connection with the initial issuance, for net proceeds of $247 million.

Distributions to Noncontrolling Interest Owners WES distributed to its unitholders other than Anadarko and WGP an aggregate of $127 million during the six months ended June 30, 2016, and $111 million during the six months ended June 30, 2015. WES has made quarterly distributions to its unitholders since its initial public offering (IPO) in the second quarter of 2008, and has increased its distribution from $0.30 per common unit for the third quarter of 2008 to $0.830 per common unit for the second quarter of 2016 (to be paid in August 2016).
For the three months ended June 30, 2016, the WES Series A Preferred unitholders will receive a quarterly distribution of $0.68 per unit for the Series A Preferred units issued in March 2016, and a quarterly distribution of $0.68 per unit for the Series A Preferred units issued in April 2016, prorated for the 77-day period the units were outstanding during the second quarter of 2016, or an aggregate $14 million (to be paid in August 2016). For the three months ended March 31, 2016, the WES Series A Preferred unitholders received a quarterly distribution of $0.68 per unit, prorated for the 18-day period the units were outstanding during the first quarter, or an aggregate $2 million (paid in May 2016).
WGP distributed to its unitholders other than Anadarko an aggregate of $23 million during the six months ended June 30, 2016, and $17 million during the six months ended June 30, 2015. WGP has made quarterly distributions to its unitholders since its IPO in December 2012, and has increased its distribution from $0.17875 per common unit for the first quarter of 2013 to $0.43375 per unit for the second quarter of 2016 (to be paid in August 2016).

RECENT ACCOUNTING DEVELOPMENTS

See *Note 1-Summary of Significant Accounting Policies* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q for discussion of recent accounting developments affecting the Company.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

The Company's primary market risks are attributable to fluctuations in energy prices and interest rates. These risks can affect revenues and cash flows, and the Company's risk-management policies provide for the use of derivative instruments to manage these risks. The types of commodity derivative instruments used by the Company include futures, swaps, options, and fixed-price physical-delivery contracts. The volume of commodity derivatives entered into by the Company is governed by risk-management policies and may vary from year to year. Both exchange and over-the-counter traded derivative instruments may be subject to margin-deposit requirements, and the Company may be required from time to time to deposit cash or provide letters of credit with exchange brokers or counterparties to satisfy these margin requirements. For additional information relating to the Company's derivative and financial instruments, see *Note 6-Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

COMMODITY-PRICE RISK The Company's most significant market risk relates to prices for oil, natural gas, and NGLs. Management expects energy prices to remain unpredictable and potentially volatile. As energy prices decline or rise significantly, revenues and cash flows are likewise affected. In addition, a non-cash write-down of the Company's oil and gas properties or goodwill may be required if commodity prices experience a significant decline. Below is a sensitivity analysis for the Company's commodity-price-related derivative instruments.

Derivative Instruments Held for Non-Trading Purposes The Company had derivative instruments in place to reduce the price risk associated with future production of 15 MMBbls of oil, 349 Bcf of natural gas, and 1 MMBbls of NGLs at June 30, 2016, with a net derivative asset position of $45 million. Based on actual derivative contractual volumes, a 10% increase in underlying commodity prices would reduce the fair value of these derivatives by $116 million, while a 10% decrease in underlying commodity prices would increase the fair value of these derivatives by $109 million. However, any cash received or paid to settle these derivatives would be substantially offset by the sales value of production covered by the derivative instruments.

Derivative Instruments Held for Trading Purposes At June 30, 2016, the Company had a net derivative asset position of $7 million on outstanding derivative instruments entered into for trading purposes. Based on actual derivative contractual volumes, a 10% increase or decrease in underlying commodity prices would not materially impact the Company's gains or losses on these derivative instruments.

INTEREST-RATE RISK Borrowings, if any, under each of the 364-Day Facility, the Five-Year Facility, the WES RCF, and the WGP RCF are subject to variable interest rates. The balance of Anadarko's long-term debt on the Company's Consolidated Balance Sheets has fixed interest rates. The Company has $2.9 billion of obligations based on the London Interbank Offered Rate (LIBOR) that are presented on the Company's Consolidated Balance Sheets net of preferred investments in two noncontrolled entities. These obligations give rise to minimal net interest-rate risk because coupons on the related preferred investments are also LIBOR-based. While a 10% change in LIBOR would not materially impact the Company's interest cost, it would affect the fair value of outstanding fixed-rate debt.

At June 30, 2016, the Company had a net derivative liability position of $1.8 billion related to interest-rate swaps. A 10% increase (decrease) in the three-month LIBOR interest-rate curve would decrease (increase) the aggregate fair value of outstanding interest-rate swap agreements by $75 million. However, any change in the interest-rate derivative gain or loss could be substantially offset by changes in actual borrowing costs associated with future debt issuances. For a summary of the Company's outstanding interest-rate derivative positions, see *Note 6-Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

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Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Anadarko's Chief Executive Officer and Chief Financial Officer performed an evaluation of the Company's disclosure controls and procedures as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (Exchange Act). The Company's disclosure controls and procedures are designed to ensure that information required to be disclosed by the Company in reports it files or submits under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission, and to ensure that the information required to be disclosed by the Company in reports that it files or submits under the Exchange Act is accumulated and communicated to the Company's management, including the principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that the Company's disclosure controls and procedures are effective as of June 30, 2016.

Changes in Internal Control over Financial Reporting

There were no changes in Anadarko's internal control over financial reporting during the second quarter of 2016 that materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

GENERAL The Company is a defendant in a number of lawsuits and is involved in governmental proceedings and regulatory controls arising in the ordinary course of business, including personal injury and death claims; title disputes; tax disputes; royalty claims; contract claims; contamination claims relating to oil and gas exploration, development, production, transportation, and processing; and environmental claims, including claims involving assets owned by acquired companies and claims involving assets previously sold to third parties and no longer a part of the Company's current operations. Anadarko is also subject to various environmental-remediation and reclamation obligations arising from federal, state, tribal, and local laws and regulations. While the ultimate outcome and impact on the Company cannot be predicted with certainty, after consideration of recorded expense and liability accruals, management believes that the resolution of pending proceedings will not have a material adverse effect on the Company's financial condition, results of operations, or cash flows.

WGR Operating, LP, a wholly owned subsidiary of the Company, is currently in negotiations with the U.S. Environmental Protection Agency and the state of Wyoming with respect to alleged noncompliance with the leak detection and repair requirements of the Clean Air Act at its Granger, Wyoming facilities. Although management cannot predict the outcome of settlement discussions, it is likely a resolution of this matter will result in a fine or penalty in excess of $100,000.

See *Note 11-Contingencies* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q, which is incorporated herein by reference, for material developments with respect to matters previously reported in the Company's Annual Report on Form 10-K for the year ended December 31, 2015, and material matters that have arisen since the filing of such report.

Item 1A. Risk Factors

There have been no material changes from the risk factors included under Part I, Item 1A of the Company's Annual Report on Form 10-K for the year ended December 31, 2015.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

The following sets forth information with respect to repurchases by the Company of its shares of common stock during the second quarter of 2016:

Period	Total number of shares purchased (1)	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs	Approximate dollar value of shares that may yet be purchased under the plans or programs
April 1 - 30, 2016	7,745	$ 49.91	-	$ -
May 1 - 31, 2016	4,346	$ 49.42	-	$ -
June 1 - 30, 2016	6,354	$ 53.44	-	$ -
Total	18,445	$ 51.01	-	$ -

(1) During the second quarter of 2016, all purchased shares related to stock received by the Company for the payment of withholding taxes due on employee share issuances under share-based compensation plans.

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Item 6. Exhibits

Exhibits designated by an asterisk (*) are filed herewith or double asterisk (**) are furnished herewith; all exhibits not so designated are incorporated herein by reference to a prior filing under File Number 1-8968 as indicated.

Exhibit Number		Description
	3 (i)	Restated Certificate of Incorporation of Anadarko Petroleum Corporation, dated May 21, 2009, filed as Exhibit 3.3 to Form 8-K filed on May 22, 2009
	(ii)	By-Laws of Anadarko Petroleum Corporation, amended and restated as of September 15, 2015, filed as Exhibit 3.1 to Form 8-K filed on September 21, 2015
	10 (i)	Form of Award Letter for Anadarko Petroleum Corporation 2008 Director Compensation Plan Annual Deferred Shares (2016), filed as Exhibit 10 (iii) to Form 10-Q filed on May 2, 2016
	(ii)	Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan, as Amended and Restated Effective as of May 10, 2016, filed as Exhibit 10.1 to Form 8-K filed on May 16, 2016
*	31 (i)	Rule 13a-14(a)/15d-14(a) Certification-Chief Executive Officer
*	31 (ii)	Rule 13a-14(a)/15d-14(a) Certification-Chief Financial Officer
**	32	Section 1350 Certifications
*	101.INS	XBRL Instance Document
*	101.SCH	XBRL Schema Document
*	101.CAL	XBRL Calculation Linkbase Document
*	101.DEF	XBRL Definition Linkbase Document
*	101.LAB	XBRL Label Linkbase Document
*	101.PRE	XBRL Presentation Linkbase Document

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ANADARKO PETROLEUM CORPORATION
(Registrant)

July 26, 2016

By: /s/ ROBERT G. GWIN

Robert G. Gwin
Executive Vice President, Finance and Chief Financial Officer

Exhibit 111

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549

FORM 8-K

CURRENT REPORT
PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934

Date of Earliest Event Reported: July 26, 2016

ANADARKO PETROLEUM CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	1-8968	76-0146568
(State or Other Jurisdiction of Incorporation)	(Commission File Number)	(IRS Employer Identification No.)

1201 Lake Robbins Drive
The Woodlands, Texas 77380-1046
(Address of principal executive offices)

Registrant's telephone number, including area code **(832) 636-1000**

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

The information in this Current Report on Form 8-K shall not be deemed to be "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (Exchange Act), or otherwise subject to the liabilities of that section, and is not incorporated by reference into any filing under the Securities Act of 1933, as amended, or the Exchange Act.

Item 2.02 Results of Operations and Financial Condition.

On July 26, 2016, Anadarko Petroleum Corporation (Anadarko) announced second-quarter 2016 financial and operating results. The press release is included in this report as Exhibit 99 and is incorporated herein by reference.

Item 7.01 Regulation FD Disclosure.

On July 26, 2016, Anadarko provided guidance for the remainder of 2016. This information is contained in the press release included in this report as Exhibit 99.

Item 9.01 Financial Statements and Exhibits.

(d) Exhibits.

99 Anadarko Press Release dated July 26, 2016.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

ANADARKO PETROLEUM CORPORATION
(Registrant)

July 26, 2016

By: /s/ CHRISTOPHER O. CHAMPION
Christopher O. Champion
Vice President, Chief Accounting Officer and Controller

EXHIBIT INDEX

Exhibit No.	Description
99	Anadarko Press Release dated July 26, 2016.

Exhibit 99

Anadarko Petroleum Corporation

NEWS

ANADARKO ANNOUNCES SECOND-QUARTER 2016 RESULTS

HOUSTON, July 26, 2016 – Anadarko Petroleum Corporation (NYSE: APC) today announced its financial and operating results for the second quarter of 2016, including a net loss attributable to common stockholders of $692 million, or $1.36 per share (diluted). The net loss includes certain items typically excluded by the investment community in published estimates, which in the aggregate decreased net income by $388 million or $0.76 per share (diluted) on an after-tax basis.(1) Cash flow from operating activities in the second quarter of 2016 was $1.229 billion. Discretionary cash flow from operations totaled $669 million.(2)

HIGHLIGHTS

- Achieved record production levels at three operated Gulf of Mexico facilities and in the U.S. onshore Delaware and DJ basins
- Encountered more than 1,040 net feet of oil pay at the Shenandoah-5 appraisal well and increased working interest in this operated deepwater discovery
- Closed $2.5 billion of monetizations year to date
- Retired $3 billion of near-term maturities with proceeds from debt issued during the first quarter

"Our portfolio continues to perform exceptionally well, and we've continued to significantly reduce our cost structure throughout the year," said Al Walker, Anadarko Chairman, President and CEO. "As a result of the record sales volumes from our Lucius and Caesar/Tonga fields in the Gulf of Mexico, as well as the improving well performance in the Delaware and DJ basins, we are increasing the midpoint of our full-year divestiture-adjusted(3) sales-volume guidance by 2 million BOE (barrels of oil equivalent). Additionally, we've been very successful monetizing assets through the first six months of this year and have increased the high end of our target range to $3.5 billion in total proceeds expected by year end. As stated previously, we intend to use sales proceeds to retire debt, including the remaining $750 million of 2017 maturities. In addition, should the commodity-price outlook continue to improve, we will evaluate redeploying some of the additional cash generated via operations and asset sales toward our highest-quality U.S. onshore opportunities."

OPERATIONS SUMMARY

Anadarko's second-quarter sales volumes of natural gas, oil and natural gas liquids (NGLs) totaled 72 million BOE, or an average of 792,000 BOE per day.

In the Delaware Basin of West Texas, Anadarko averaged record net sales volumes of 41,000 BOE per day, and exited the quarter at approximately 45,000 BOE per day. The company has continued its delineation program, running six rigs to further its understanding of both the vertical and areal potential across its 600,000-gross-acre position in the heart of the play. In the DJ Basin of northeast Colorado, Anadarko continued to optimize the performance of its base production during the second quarter, achieving record net sales volumes of approximately 243,000 BOE per day.

In the Gulf of Mexico, the company achieved several production records. The Lucius platform achieved a 24-hour gross production record and averaged sales volumes above the facility's 80,000 barrels of oil per day (BOPD) nameplate capacity. In addition, the company's Constitution spar recently achieved a production record of 65,000 BOPD, and its K2 complex also achieved an eight-year-high production rate of 28,000 BOPD. During the quarter, Anadarko continued to advance its understanding of the Shenandoah discovery, as it encountered more than 1,040 net feet of oil pay in the Shenandoah-5 appraisal well, expanding the eastern extent of the field. Additionally, the company increased its working interest in Shenandoah to 33 percent and added several new exploration opportunities to the portfolio by participating in a preferential-right process.

Internationally, the TEN field offshore Ghana is 97-percent complete with installation, hook-up and commissioning on schedule and first oil expected in the third quarter of 2016. At the adjacent Jubilee field, following maintenance on the floating production, storage and offloading vessel (FPSO) and implementation of new production and offtake procedures, production has ramped back up and is expected to average approximately 85,000 BOPD during the second half of the year. The partnership determined a long-term solution to convert the FPSO to a permanently moored facility, with the work program expected to be completed in the first half of 2017. Until the work program is complete, shuttle tankers will continue to be utilized to deliver offtake. Offshore Côte d'Ivoire, Anadarko continued its successful appraisal program with the drilling of the Paon-3AR horizontal sidetrack, which will be followed by a drillstem and interference testing program in the third quarter. In advancing the Mozambique LNG project, Anadarko achieved a significant milestone by submitting the Resettlement Plan for government review.

OPERATIONS REPORT

For details on Anadarko's operations and exploration program, including detailed tables illustrating divestiture-adjusted[3] information, please refer to the comprehensive report on second-quarter 2016 activity. The report is available at www.anadarko.com.

FINANCIAL SUMMARY

Anadarko ended the second quarter with approximately $1.4 billion of cash on hand. Year to date, Anadarko has generated approximately $2.5 billion in monetizations, including proceeds received during the second quarter from the secondary offering of Western Gas Equity Partners (NYSE: WGP) common units and divestitures of the company's Wamsutter and non-core Permian assets.

CONFERENCE CALL *TOMORROW* AT 8 A.M. CDT, 9 A.M. EDT

Anadarko will host a conference call on Wednesday, July 27, 2016, at 8 a.m. Central Daylight Time (9 a.m. Eastern Daylight Time) to discuss second-quarter results, current operations and the company's outlook for the remainder of 2016. The dial-in number is 877.883.0383 in the United States or 412.902.6506 internationally. The confirmation number is 0728576. For complete instructions on how to participate in the conference call, or to listen to the live audio webcast and slide presentation, please visit www.anadarko.com. A replay of the call will be available on the website for approximately 30 days following the conference call.

FINANCIAL DATA

Nine pages of summary financial data follow, including current hedge positions, a reconciliation of "divestiture-adjusted" or "same-store" sales, and updated financial and production guidance.

(1) See the accompanying table for details of certain items affecting comparability.
(2) See the accompanying table for a reconciliation of GAAP to non-GAAP financial measures and a statement indicating why management believes the non-GAAP financial measures provide useful information for investors.
(3) See the accompanying table for a reconciliation of "divestiture-adjusted" or "same-store" sales volumes, which are intended to present performance of Anadarko's continuing asset base, giving effect to recent divestitures.

Anadarko Petroleum Corporation's mission is to deliver a competitive and sustainable rate of return to shareholders by exploring for, acquiring and developing oil and natural gas resources vital to the world's health and welfare. As of year-end 2015, the company had approximately 2.06 billion barrels-equivalent of proved reserves, making it one of the world's largest independent exploration and production companies. For more information about Anadarko and Flash Feed updates, please visit www.anadarko.com.

This news release contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Anadarko believes that its expectations are based on reasonable assumptions. No assurance, however, can be given that such expectations will prove to have been correct. A number of factors could cause actual results to differ materially from the projections, anticipated results or other expectations expressed in this news release, including Anadarko's ability to realize its expectations regarding performance in this challenging economic environment and meet financial and operating guidance, identify and complete additional monetization transactions, reduce its debt, timely complete and commercially operate the projects and drilling prospects identified in this news release, and successfully plan, secure necessary government approvals, enter into long-term sales contracts, finance, build and operate the necessary infrastructure and LNG park in Mozambique. See "Risk Factors" in the company's 2015 Annual Report on Form 10-K, Quarterly Reports on Form 10-Q and other public filings and press releases. Anadarko undertakes no obligation to publicly update or revise any forward-looking statements.

# # #

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Anadarko Petroleum Corporation
Reconciliation of GAAP to Non-GAAP Measures

Below are reconciliations of net income (loss) attributable to common stockholders (GAAP) to adjusted net income (loss) (non-GAAP), cash provided by operating activities (GAAP) to discretionary cash flow from operations (non-GAAP) and free cash flow (non-GAAP), and total debt (GAAP) to net debt (non-GAAP), each as required under Regulation G of the Securities Exchange Act of 1934. The Company also provides non-GAAP definitions and reconciliations on its website located at www.anadarko.com/investor-kit. This non-GAAP information should be considered by the reader in addition to, but not instead of, the financial statements prepared in accordance with GAAP. The non-GAAP financial information presented may be determined or calculated differently by other companies and may not be comparable to similarly titled measures.

Management uses adjusted net income (loss) to evaluate operating and financial performance and believes the measure is useful to investors because it eliminates the impact of certain noncash and/or other items that management does not consider to be indicative of the Company's performance from period to period. Management also believes this non-GAAP measure is useful to investors to evaluate and compare the Company's operating and financial performance across periods, as well as facilitating comparisons to others in the Company's industry.

	Quarter Ended June 30, 2016		
millions except per-share amounts	Before Tax	After Tax	Per Share (diluted)
Net income (loss) attributable to common stockholders		**$ (692)**	**$ (1.36)**
Adjustments for certain items affecting comparability			
Total gains (losses) on derivatives, net, less net cash from settlement of commodity derivatives*	**$ (371)**	**(234)**	**(0.46)**
Gains (losses) on divestitures, net	**(104)**	**(66)**	**(0.13)**
Impairments	**(18)**	**(11)**	**(0.02)**
Restructuring charges	**(48)**	**(30)**	**(0.06)**
Loss on early extinguishment of debt	**(124)**	**(78)**	**(0.15)**
Third-party well and platform decommissioning obligation	**56**	**35**	**0.07**
Change in uncertain tax positions (FIN 48)	**—**	**(4)**	**(0.01)**
Certain items affecting comparability	**$ (609)**	**(388)**	**(0.76)**
Adjusted net income (loss)		**$ (304)**	**$ (0.60)**

* Includes $(213) million related to interest-rate derivatives, $(154) million related to commodity derivatives, and $(4) million related to gathering, processing, and marketing sales.

	Quarter Ended June 30, 2015		
millions except per-share amounts	Before Tax	After Tax	Per Share (diluted)
Net income (loss) attributable to common stockholders		$ 61	$ 0.12
Adjustments for certain items affecting comparability			
Total gains (losses) on derivatives, net, less net cash from settlement of commodity derivatives*	$ 229	145	0.28
Gains (losses) on divestitures, net	(91)	(77)	(0.15)
Impairments	(30)	(20)	(0.04)
Change in uncertain tax positions (FIN 48)	—	9	0.02
Certain items affecting comparability	$ 108	57	0.11
Adjusted net income (loss)		$ 4	$ 0.01

* Includes $312 million related to interest-rate derivatives and $(83) million related to commodity derivatives.

Anadarko Petroleum Corporation
Reconciliation of GAAP to Non-GAAP Measures

Management believes that discretionary cash flow from operations and free cash flow are useful to management and investors as a measure of a company's ability to internally fund its capital expenditures and to service or incur additional debt. These measures eliminate the impact of certain items that management does not consider to be indicative of the Company's performance from period to period.

	Quarter Ended June 30,		Six Months Ended June 30,	
millions	**2016**	2015	**2016**	2015
Net cash provided by (used in) operating activities	**$ 1,229**	$ 1,243	**$ 1,092**	$ (3,261)
Add back				
Increase (decrease) in accounts receivable	**(876)**	462	**(922)**	105
(Increase) decrease in accounts payable and accrued expenses	**314**	(81)	**717**	198
Other items, net	**14**	(339)	**100**	269
Tronox settlement payment	**—**	—	**—**	5,215
Certain nonoperating and other excluded items	**(12)**	—	**168**	26
Current taxes related to asset monetizations	**—**	88	**—**	316
Discretionary cash flow from operations	**$ 669**	$ 1,373	**$ 1,155**	$ 2,868
Less capital expenditures*	**728**	1,401	**1,624**	3,223
Free cash flow**	**$ (59)**	$ (28)	**$ (469)**	$ (355)

* Includes Western Gas Partners, LP (WES) capital expenditures of $120 million for the quarter ended June 30, 2016, and $122 million for the quarter ended June 30, 2015, $260 million for the six months ended June 30, 2016, and $278 million for the six months ended June 30, 2015.

** Free cash flow for the six months ended June 30, 2015, includes a $595 million current tax benefit associated with the Tronox settlement.

Management uses net debt to determine the Company's outstanding debt obligations that would not be readily satisfied by its cash and cash equivalents on hand. Management believes that using net debt in the capitalization ratio is useful to investors in determining the Company's leverage since the Company could choose to use its cash and cash equivalents to retire debt. In addition, management believes that presenting Anadarko's net debt excluding WGP is useful because WGP is a separate public company with its own capital structure.

	June 30, 2016		
millions	**Anadarko Consolidated**	**WGP* Consolidated**	**Anadarko excluding WGP**
Total debt	**$ 15,673**	**$ 2,960**	**$ 12,713**
Less cash and cash equivalents	**1,394**	**160**	**1,234**
Net debt	**$ 14,279**	**$ 2,800**	**$ 11,479**

millions	**Anadarko Consolidated**	**Anadarko excluding WGP**
Net debt	**$ 14,279**	**$ 11,479**
Total equity	**14,600**	**11,281**
Adjusted capitalization	**$ 28,879**	**$ 22,760**
Net debt to adjusted capitalization ratio	**49%**	**50%**

* Western Gas Equity Partners, LP (WGP) is a publicly traded consolidated subsidiary of Anadarko and WES is a consolidated subsidiary of WGP.

Anadarko Petroleum Corporation
(Unaudited)

Summary Financial Information	Quarter Ended June 30,		Six Months Ended June 30,	
millions except per-share amounts	**2016**	2015	**2016**	2015
Consolidated Statements of Income				
Revenues and Other				
Oil and condensate sales	**$ 1,125**	$ 1,616	**$ 1,975**	$ 3,035
Natural-gas sales	**320**	487	**$ 686**	1,128
Natural-gas liquids sales	**235**	229	**413**	461
Gathering, processing, and marketing sales	**305**	305	**545**	598
Gains (losses) on divestitures and other, net	**(70)**	(1)	**(30)**	(265)
Total	**1,915**	2,636	**3,589**	4,957
Costs and Expenses				
Oil and gas operating	**202**	226	**410**	522
Oil and gas transportation	**246**	283	**488**	588
Exploration	**76**	103	**202**	1,186
Gathering, processing, and marketing	**252**	255	**467**	509
General and administrative	**305**	278	**754**	585
Depreciation, depletion, and amortization	**984**	1,214	**2,133**	2,470
Other taxes	**157**	151	**274**	333
Impairments	**18**	30	**34**	2,813
Other operating expense	**7**	6	**23**	69
Total	**2,247**	2,546	**4,785**	9,075
Operating Income (Loss)	**(332)**	90	**(1,196)**	(4,118)
Other (Income) Expense				
Interest expense	**217**	201	**437**	417
Loss on early extinguishment of debt	**124**	—	**124**	—
(Gains) losses on derivatives, net	**307**	(311)	**604**	(159)
Other (income) expense, net	**(55)**	15	**(55)**	62
Tronox-related contingent loss	**—**	—	**—**	5
Total	**593**	(95)	**1,110**	325
Income (Loss) Before Income Taxes	**(925)**	185	**(2,306)**	(4,443)
Income tax expense (benefit)	**(314)**	77	**(697)**	(1,315)
Net Income (Loss)	**(611)**	108	**(1,609)**	(3,128)
Net income (loss) attributable to noncontrolling interests	**81**	47	**117**	79
Net Income (Loss) Attributable to Common Stockholders	**$ (692)**	$ 61	**$ (1,726)**	$ (3,207)
Per Common Share				
Net income (loss) attributable to common stockholders—basic	**$ (1.36)**	$ 0.12	**$ (3.39)**	$ (6.32)
Net income (loss) attributable to common stockholders—diluted	**$ (1.36)**	$ 0.12	**$ (3.39)**	$ (6.32)
Average Number of Common Shares Outstanding—Basic	**510**	508	**510**	507
Average Number of Common Shares Outstanding—Diluted	**510**	509	**510**	507

Exploration Expense				
Dry hole expense	**$ (5)**	$ 13	**$ 6**	$ 42
Impairments of unproved properties	**15**	18	**39**	998
Geological and geophysical expense	**32**	16	**69**	38
Exploration overhead and other	**34**	56	**88**	108
Total	**$ 76**	$ 103	**$ 202**	$ 1,186

Anadarko Petroleum Corporation
(Unaudited)

Summary Financial Information *millions*	Quarter Ended June 30, 2016	Quarter Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Cash Flows from Operating Activities				
Net income (loss)	**$ (611)**	$ 108	**$ (1,609)**	$ (3,128)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities				
Depreciation, depletion, and amortization	**984**	1,214	**2,133**	2,470
Deferred income taxes	**(407)**	11	**(820)**	(1,187)
Dry hole expense and impairments of unproved properties	**10**	31	**45**	1,040
Impairments	**18**	30	**34**	2,813
(Gains) losses on divestitures, net	**104**	91	**102**	425
Loss on early extinguishment of debt	**124**	—	**124**	—
Total (gains) losses on derivatives, net	**311**	(310)	**610**	(158)
Operating portion of net cash received (paid) in settlement of derivative instruments	**60**	81	**165**	172
Other	**88**	29	**203**	74
Changes in assets and liabilities				
Tronox-related contingent liability	**—**	—	**—**	(5,210)
(Increase) decrease in accounts receivable	**876**	(462)	**922**	(105)
Increase (decrease) in accounts payable and accrued expenses	**(314)**	81	**(717)**	(198)
Other items, net	**(14)**	339	**(100)**	(269)
Net Cash Provided by (Used in) Operating Activities	**$ 1,229**	$ 1,243	**$ 1,092**	$ (3,261)
Capital Expenditures	**$ 728**	$ 1,401	**$ 1,624**	$ 3,223

millions	June 30, 2016	December 31, 2015
Condensed Balance Sheets		
Cash and cash equivalents	**$ 1,394**	$ 939
Accounts receivable, net of allowance	**1,500**	2,469
Other current assets	**318**	573
Net properties and equipment	**32,345**	33,751
Other assets	**2,239**	2,268
Goodwill and other intangible assets	**6,237**	6,331
Total Assets	**$ 44,033**	$ 46,331
Short-term debt	**32**	32
Other current liabilities	**3,212**	4,148
Long-term debt	**15,641**	15,636
Deferred income taxes	**4,686**	5,400
Other long-term liabilities	**5,862**	5,658
Stockholders' equity	**11,281**	12,819
Noncontrolling interests	**3,319**	2,638
Total Equity	**$ 14,600**	$ 15,457
Total Liabilities and Equity	**$ 44,033**	$ 46,331
Capitalization		
Total debt	**$ 15,673**	$ 15,668
Total equity	**14,600**	15,457
Total	**$ 30,273**	$ 31,125

Capitalization Ratios		
Total debt	**52%**	50%
Total equity	**48%**	50%

Anadarko Petroleum Corporation
(Unaudited)

Sales Volumes and Prices

	Average Daily Sales Volumes			Sales Volumes			Average Sales Price		
	Oil & Condensate MBbls/d	Natural Gas MMcf/d	NGLs MBbls/d	Oil & Condensate MMBbls	Natural Gas Bcf	NGLs MMBbls	Oil & Condensate Per Bbl	Natural Gas Per Mcf	NGLs Per Bbl
Quarter Ended June 30, 2016									
United States	**227**	**2,188**	**126**	**20**	**199**	**12**	**$ 40.25**	**$ 1.61**	**$ 19.42**
Algeria	**59**	**—**	**5**	**5**	**—**	**1**	**46.65**	**—**	**24.13**
Other International	**10**	**—**	**—**	**1**	**—**	**—**	**47.37**	**—**	**—**
Total	**296**	**2,188**	**131**	**26**	**199**	**13**	**$ 41.77**	**$ 1.61**	**$ 19.60**
Quarter Ended June 30, 2015									
United States	240	2,354	130	21	215	12	$ 54.14	$ 2.28	$ 17.98
Algeria	50	—	6	5	—	—	60.24	—	31.11
Other International	28	—	—	3	—	—	61.82	—	—
Total	318	2,354	136	29	215	12	$ 55.78	$ 2.28	$ 18.50
Six Months Ended June 30, 2016									
United States	**229**	**2,245**	**125**	**41**	**409**	**23**	**$ 34.07**	**$ 1.68**	**$ 17.24**
Algeria	**62**	**—**	**5**	**11**	**—**	**1**	**40.35**	**—**	**23.43**
Other International	**14**	**—**	**—**	**3**	**—**	**—**	**37.55**	**—**	**—**
Total	**305**	**2,245**	**130**	**55**	**409**	**24**	**$ 35.51**	**$ 1.68**	**$ 17.49**
Six Months Ended June 30, 2015									
United States	238	2,545	134	43	461	24	$ 49.23	$ 2.45	$ 17.63
Algeria	60	—	6	11	—	1	57.80	—	32.01
Other International	28	—	—	5	—	—	55.69	—	—
Total	326	2,545	140	59	461	25	$ 51.37	$ 2.45	$ 18.24

	Average Daily Sales Volumes MBOE/d	Sales Volumes MMBOE
Quarter Ended June 30, 2016	**792**	**72**
Quarter Ended June 30, 2015	846	77
Six Months Ended June 30, 2016	**809**	**147**
Six Months Ended June 30, 2015	890	161

Sales Revenue and Commodity Derivatives

	Sales			Net Cash Received (Paid) from Settlement of Commodity Derivatives		
millions	Oil & Condensate	Natural Gas	NGLs	Oil & Condensate	Natural Gas	NGLs
Quarter Ended June 30, 2016						
United States	**$ 830**	**$ 320**	**$ 223**	**$ 60**	**$ 2**	**$ (2)**
Algeria	**252**	**—**	**12**	**—**	**—**	**—**
Other International	**43**	**—**	**—**	**—**	**—**	**—**
Total	**$ 1,125**	**$ 320**	**$ 235**	**$ 60**	**$ 2**	**$ (2)**
Quarter Ended June 30, 2015						
United States	$ 1,181	$ 487	$ 213	$ 3	$ 77	$ 2
Algeria	277	—	16	—	—	—
Other International	158	—	—	—	—	—

Total	$ 1,616	$ 487	$ 229	$ 3	$ 77	$ 2
Six Months Ended June 30, 2016						
United States	**$ 1,421**	**$ 686**	**$ 390**	**$ 148**	**$ 15**	**$ —**
Algeria	**458**	**—**	**23**	**—**	**—**	**—**
Other International	**96**	**—**	**—**	**—**	**—**	**—**
Total	**$ 1,975**	**$ 686**	**$ 413**	**$ 148**	**$ 15**	**$ —**
Six Months Ended June 30, 2015						
United States	$ 2,121	$ 1,128	$ 426	$ 5	$ 150	$ 17
Algeria	629	—	35	—	—	—
Other International	285	—	—	—	—	—
Total	$ 3,035	$ 1,128	$ 461	$ 5	$ 150	$ 17

Anadarko Petroleum Corporation
Financial and Operating External Guidance
As of July 26, 2016

Note: Guidance excludes 2016 sales volumes associated with the East Chalk and Wamsutter divestitures.

	3rd-Qtr Guidance (see Note)			Full-Year Guidance (see Note)		
	Units			Units		
Total Sales Volumes (MMBOE)	68	—	70	277	—	281
Total Sales Volumes (MBOE/d)	739	—	761	757	—	768
Oil (MBbl/d)	301	—	307	303	—	308
United States	222	—	225	223	—	226
Algeria	62	—	64	63	—	64
Ghana	17	—	18	17	—	18
Natural Gas (MMcf/d)						
United States	1,895	—	1,935	2,000	—	2,020
Natural Gas Liquids (MBbl/d)						
United States	114	—	118	114	—	117
Algeria	5	—	7	5	—	7
	$ / Unit			$ / Unit		
Price Differentials vs NYMEX (w/o hedges)						
Oil ($/Bbl)	(6.70)	—	(2.20)	(6.90)	—	(2.50)
United States	(8.00)	—	(3.00)	(8.00)	—	(3.00)
Algeria	(3.00)	—	—	(4.00)	—	(1.00)
Ghana	(3.00)	—	—	(4.00)	—	(1.00)
Natural Gas ($/Mcf)						
United States	(0.55)	—	(0.40)	(0.45)	—	(0.35)

Anadarko Petroleum Corporation
Financial and Operating External Guidance
As of July 26, 2016

Note: Guidance excludes items affecting comparability.

	3rd-Qtr Guidance (see Note)			Full-Year Guidance (see Note)		
	$ MM			$ MM		
Other Revenues						
Marketing and Gathering Margin	20	—	40	120	—	140
Minerals and Other	35	—	55	155	—	175
	$ / BOE			$ / BOE		
Costs and Expenses						
Oil & Gas Direct Operating	3.15	—	3.30	3.05	—	3.25
Oil & Gas Transportation	3.20	—	3.40	3.25	—	3.45
Depreciation, Depletion, and Amortization	14.90	—	15.35	14.80	—	15.00
Production Taxes (% of Product Revenue)	8.0%	—	9.0%	8.0%	—	9.0%
	$ MM			$ MM		
General and Administrative (excludes restructuring charges)	245	—	265	950	—	1,000
Other Operating Expense	25	—	35	75	—	85
Exploration Expense						
Non-Cash	40	—	60	350	—	450
Cash	50	—	70	260	—	280
Interest Expense (net)	210	—	225	865	—	885
Other (Income) Expense (includes noncontrolling interest)	70	—	80	250	—	275
Taxes						
Algeria (100% current)	60%	—	70%	65%	—	75%
Rest of Company (10% Current/90% Deferred for Q3 and Total Year)	35%	—	45%	30%	—	40%
Avg. Shares Outstanding (MM)						
Basic	510	—	511	510	—	511
Diluted	510	—	511	511	—	512
Capital Investment (Excluding Western Gas Partners, LP)	$ MM			$ MM		
APC Capital Expenditures	650	—	750	2,600	—	2,800

Anadarko Petroleum Corporation
Commodity Hedge Positions
As of July 26, 2016

	Volume (MBbls/d)	Weighted Average Price per barrel					
		Floor Sold		Floor Purchased		Ceiling Sold	
Oil							
Three-Way Collars							
2016							
WTI	65	$	41.54	$	53.08	$	62.25
Brent	18	$	47.22	$	59.44	$	69.47
	83	$	42.77	$	54.46	$	63.82

	Volume (thousand MMBtu/d)	Weighted Average Price per MMBtu					
		Floor Sold		Floor Purchased		Ceiling Sold	
Natural Gas							
Three-Way Collars							
2017	682	$	2.00	$	2.75	$	3.60
2018	250	$	2.00	$	2.75	$	3.54

Interest-Rate Derivatives

As of July 26, 2016

Instrument	Notional Amt.	Reference Period	Mandatory Termination Date	Rate Paid	Rate Received
Swap	$50 Million	Sept. 2016 – 2026	Sept. 2016	5.910%	3M LIBOR
Swap	$50 Million	Sept. 2016 – 2046	Sept. 2016	6.290%	3M LIBOR
Swap	$500 Million	Sept. 2016 – 2046	Sept. 2018	6.559%	3M LIBOR
Swap	$300 Million	Sept. 2016 – 2046	Sept. 2020	6.509%	3M LIBOR
Swap	$450 Million	Sept. 2017 – 2047	Sept. 2018	6.445%	3M LIBOR
Swap	$100 Million	Sept. 2017 – 2047	Sept. 2020	6.891%	3M LIBOR
Swap	$250 Million	Sept. 2017 – 2047	Sept. 2021	6.570%	3M LIBOR

Anadarko Petroleum Corporation
Reconciliation of Same-Store Sales

Average Daily Sales Volumes

	Quarter Ended March 31, 2016				Quarter Ended March 31, 2015			
	Oil & Condensate MBbls/d	Natural Gas MMcf/d	NGLs MBbls/d	Total MBOE/d	Oil & Condensate MBbls/d	Natural Gas MMcf/d	NGLs MBbls/d	Total MBOE/d
U.S. Onshore	**162**	**2,125**	**110**	**626**	166	2,138	125	647
Deepwater Gulf of Mexico	**58**	**85**	**7**	**79**	46	221	6	89
International and Alaska	**93**	**—**	**6**	**99**	107	—	7	114
Same-Store Sales	**313**	**2,210**	**123**	**804**	319	2,359	138	850
Divestitures*	**2**	**93**	**5**	**23**	16	379	5	84
Total	**315**	**2,303**	**128**	**827**	335	2,738	143	934

	Quarter Ended June 30, 2016				Quarter Ended June 30, 2015			
	Oil & Condensate MBbls/d	Natural Gas MMcf/d	NGLs MBbls/d	Total MBOE/d	Oil & Condensate MBbls/d	Natural Gas MMcf/d	NGLs MBbls/d	Total MBOE/d
U.S. Onshore	**157**	**2,033**	**116**	**612**	172	1,889	117	604
Deepwater Gulf of Mexico	**56**	**73**	**6**	**74**	57	113	7	83
International and Alaska	**81**	**—**	**5**	**86**	87	—	6	93
Same-Store Sales	**294**	**2,106**	**127**	**772**	316	2,002	130	780
Divestitures*	**2**	**82**	**4**	**20**	2	352	6	66
Total	**296**	**2,188**	**131**	**792**	318	2,354	136	846

	Six Months Ended June 30, 2016				Six Months Ended June 30, 2015			
	Oil & Condensate MBbls/d	Natural Gas MMcf/d	NGLs MBbls/d	Total MBOE/d	Oil & Condensate MBbls/d	Natural Gas MMcf/d	NGLs MBbls/d	Total MBOE/d
U.S. Onshore	**159**	**2,079**	**113**	**618**	169	2,013	122	626
Deepwater Gulf of Mexico	**57**	**78**	**7**	**77**	51	167	7	86
International and Alaska	**87**	**—**	**5**	**92**	97	—	6	103
Same-Store Sales	**303**	**2,157**	**125**	**787**	317	2,180	135	815
Divestitures*	**2**	**88**	**5**	**22**	9	365	5	75
Total	**305**	**2,245**	**130**	**809**	326	2,545	140	890

* Includes Wamsutter, East Chalk, EOR, Bossier, and Powder River Basin CBM.

Average Daily Sales Volumes

	Year Ended December 31, 2015			
	Oil & Condensate MBbls/d	Natural Gas MMcf/d	NGLs MBbls/d	Total MBOE/d
U.S. Onshore	163	1,909	111	593
Deepwater Gulf of Mexico	53	152	7	85
International and Alaska	94	—	6	100
Same-Store Sales	310	2,061	124	778
Divestitures*	7	273	6	58
Total	317	2,334	130	836

* Includes Wamsutter, East Chalk, EOR, Bossier, and Powder River Basin CBM.

Exhibit 112

S&P Global
Market Intelligence

Exhibit
425

Anadarko Petroleum Corporation

NYSE:APC

FQ2 2016 Earnings Call Transcripts

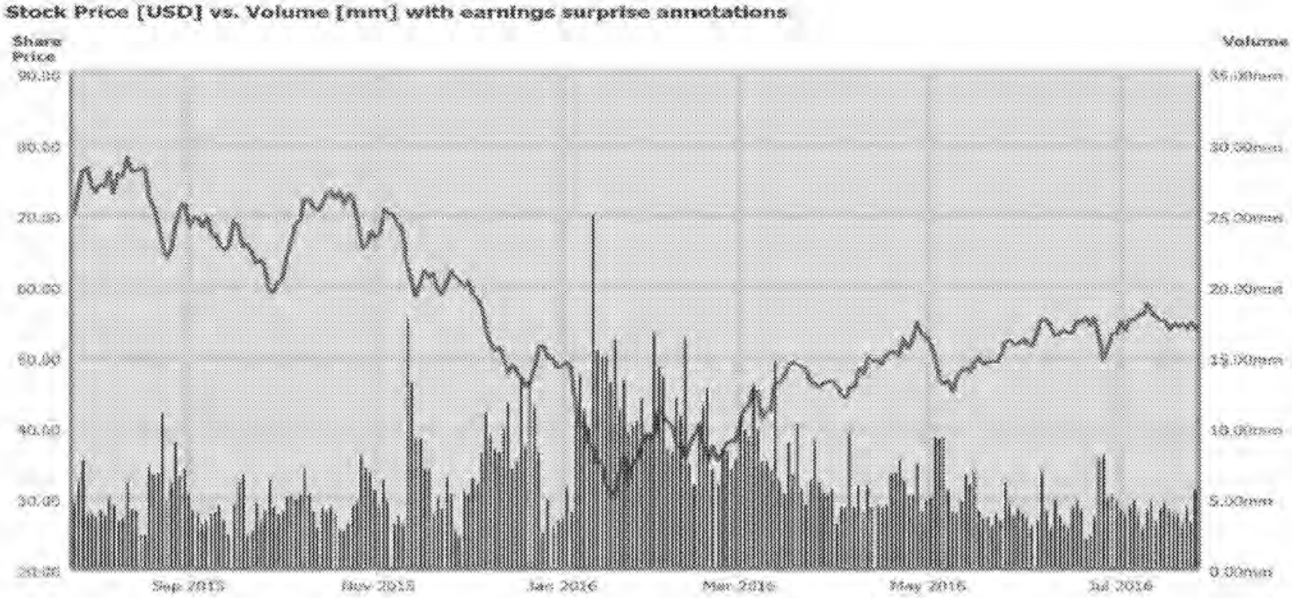
Wednesday, July 27, 2016 1:00 PM GMT

S&P Global Market Intelligence Estimates

	-FQ2 2016-			-FQ3 2016-	-FY 2016-	-FY 2017-
	CONSENSUS	ACTUAL	SURPRISE	CONSENSUS	CONSENSUS	CONSENSUS
EPS Normalized	(0.78)	(0.60)	NM	(0.55)	(3.00)	(0.93)
Revenue (mm)	1926.56	1915.00	▼(0.60 %)	2166.83	7904.85	10281.63

Currency: USD
Consensus as of Jul-27-2016 11:05 AM GMT

Stock Price [USD] vs. Volume [mm] with earnings surprise annotations



	- EPS NORMALIZED -		
	CONSENSUS	ACTUAL	SURPRISE
FQ3 2015	(0.74)	(0.72)	NM
FQ4 2015	(1.09)	(0.57)	NM
FQ1 2016	(1.18)	(1.12)	NM
FQ2 2016	(0.78)	(0.60)	NM

Table of Contents

Call Participants

EXECUTIVES

Darrell E. Hollek
Former Executive Vice President of Operations

James J. Kleckner
Former Executive Vice President of International and Deepwater Operations

John M. Colglazier
Investor Relations Professional

R. A. Walker
Chairman & CEO

Robert G. Gwin
President

ANALYSTS

Arun Jayaram
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Charles Arthur Meade
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David Robert Tameron
Wells Fargo Securities, LLC, Research Division

Douglas George Blyth Leggate
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Ryan M. Todd
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Presentation

Operator

Good morning, and welcome to the Anadarko Petroleum Second Quarter 2016 Earnings Conference Call. [Operator Instructions] Please also note, today's event is being recorded.

I would now like to turn the conference over to John. Please go ahead, sir.

John M. Colglazier
Investor Relations Professional

Well, thank you, Rocco. Good morning, everyone. We're glad you could join us today for Anadarko's second quarter 2016 conference calls.

I would like to remind you that today's presentation includes forward-looking statements and certain non-GAAP financial measures, and be aware that a number of factors could cause results to differ materially from what we discuss today. So I encourage you to read our full disclosure on forward-looking statements and the GAAP reconciliations located on our website and attached to yesterday's earnings release.

In just a moment, I'll turn the call over to Al Walker for some brief opening remarks, but first, I'd like to thank Jeremy Smith for his contributions he's made to the IR group over the last couple of years. Jeremy is now in his new role as Vice President of Mozambique project finance.

And along with that, I'd like to introduce Pete Zagrzecki, who has joined IR and will be available to assist with questions later this afternoon, along with the rest of our team.

I'll also remind you that we have a lot of additional detail in our quarterly ops report available on our website. And following Al's prepared remarks, we'll open it up for questions with our executive team. Al?

R. A. Walker
Chairman & CEO

Thanks, John, and good morning. As we turn the corner into the second half of 2016, we've made exceptional progress on the goals we established for this year of enhancing value, strengthening the balance sheet, high grading the portfolio and reducing costs.

In terms of enhancing value, our operating organization has done a tremendous job achieving several milestones during the quarter. As you can see in our operations report available online, we had outstanding performance in the Gulf of Mexico. This is an area, where we hold several competitive advantages: a successful exploration track record, an industry-leading project management capability and a large operated infrastructure position.

Our Gulf assets provide us a capital efficient value driver, and our record production achievements at Constitution and K2 are great examples of that. Our operators at Lucius facility also achieved record production during the quarter, with oil volumes exceeding nameplate capacity. As I suspect you noticed in our ops report, we drove another appraisal well at Shenandoah. The Shenandoah 5 well encountered more than 1,000 feet of net oil pay and expanded the eastern extent of the field with planning of the Shen 6 now underway.

We have a 33% working interest in Shenandoah after participating in a pref right process, and through that process, we picked up some additional blocks and exploration opportunities at no cost.

Record production levels were also achieved in the DJ and the Delaware Basins, and we were able to increase our activity over our initial expectations, while still keeping capital expenditures within guidance.

In the Delaware Basin, we have further reduced our DC&E cost per well and improved our drilling cycle times, while advancing our delineation program across a very large acreage position.

In the DJ Basin, we achieved record production, while lowering our LOE by about 15% year-over-year. Our outstanding operating results are complemented by another year of strong monetization results. In the first quarter, we announced approximately $1.3 billion of monetizations. Since then, we've achieved and have received an additional $1.2 billion of proceeds and executed a successful secondary offering of WGP units.

We now expect total proceeds to be at or above $3.5 billion for the full year. So far this year, through the cost structure improvements I have mentioned as well as the dividend reduction and monetization efforts, we have significantly strengthened the balance sheet.

We've done this by retiring $3 billion of near-term maturities with our first quarter '16 covenant issuance and planning to retire the remaining $750 million of 2017 maturities from our monetization proceeds.

The cautious approach we outlined for oil price recovery at the beginning of 2015 has played out much as we anticipated. It now appears U.S. oil supply peaked at around 9.6 million barrels per day, and we expect it to bottom out around 8 million barrels per day, all the while with global demand now exceeding expectations.

Given this dynamic, I am now encouraged that a sustained $60 oil price environment is likely to emerge as we move into 2017. This price level should provide the necessary cash margins and resulting cash cycle improvements to encourage us to accelerate activity and achieve strong returns. In this scenario, we would evaluate redeploying some of the incremental proceeds from asset sales towards our highest quality U.S. onshore assets later this year.

Our unique positions in the DJ and Delaware Basins, combined with the tieback opportunities in the Gulf of Mexico, give us strong line of sight for attractive, capital efficient, short cycle oil investments as crude prices recover.
With that, we would love to take your questions, and thanks for joining us this morning.

Question and Answer

Operator

[Operator Instructions] Today's first question comes from Evan Calio of Morgan Stanley.

Evan Calio
Morgan Stanley, Research Division

You guys continue to run 6 rigs in the Delaware. I know you mentioned it in some of your opening comments, but you'd previously mentioned lowering it to 4. Should we expect 6 rigs all year? And that's where you're recycling some of the cost savings in the flat CapEx guidance? Or is there a ramp for even potentially higher rig count with asset sales?

Darrell E. Hollek
Former Executive Vice President of Operations

Yes, Evan, this is Darrell. The plan was 4, but I can tell you we've seen continued reductions in some of our cost structure and some increased efficiencies. And so we've just elected to continue to get more activities done with that same capital that was allocated at the beginning of the year. And so as far as other activities, looking forward, that really just depends on the progress we make from here on.

Evan Calio
Morgan Stanley, Research Division

Okay. So at least with regard to the 6, I mean, should we expect completion activity to match the rig count in 2H? And was that factored in your current higher guidance?

R. A. Walker
Chairman & CEO

If I could, this is Al. I think, a lot of that's going to be very dependent upon what we anticipate to be a recovery in oil prices, but we're going to watch that pretty closely before we commit beyond the comments we're giving you this morning. But I'm -- for the first time since January of 2015, I think we see a window to better oil prices. And I foreshadowed this a little bit at the Wells Conference a few months ago, when I made the comments there that we anticipated we'd have a letdown as the market tried to absorb the 3 million barrels associated with disruptions from Venezuela, Nigeria and Canada. And as the market went through that congestion, we've -- we were going to see the leg down that we're seeing right now. And I think once we get behind -- we get that behind us, to use an economics term, ceteris paribus, we think we're looking at a sustained $60 oil price environment for next year. But I think to the question you're asking, do we see greater evidence that our thoughts are in fact true, we'll be a little slow and probably more likely to be willing to communicate that with greater clarity next quarter.

Evan Calio
Morgan Stanley, Research Division

That's helpful. Maybe one more if I could. Moving offshore, which also ducktails, I think, with your oil price outlook. You reported positive appraisal results in Shenandoah-5 with 6 upcoming. I mean, post 6, what else do you need here to reach FID, either from appraisal or technical information gathered or from an oil price environment to again to get FID?

Robert G. Gwin
President

Yes, Evan, we were real pleased with what we saw in the #5 well. Not surprised, but we were very pleased to see it come in as we had predicted it would; 1,040-plus feet of pay. We're about 0.5 mile east of the #2 well, and then we're going to move farther east and down dip with the #6. With your question of what else it's going to take, we really have to see what the #6 tells us. If the #6 comes in as we project with the oil-water contacts, we'll probably need to then do a sidetrack out of that, try to go up dip, get in a full oil

column in that. And -- so the ultimate planning has to be after #6. We've got a lot of work that's going on right now though related to how we might develop this field. But again, we're still in the appraisal mode, and so we need to get the rest of the information in front of us.

Evan Calio
Morgan Stanley, Research Division

Right. So I guess within your issue...

R. A. Walker
Chairman & CEO

I'm sorry, Evan, we talked over you. Go ahead. What was your question?

Evan Calio
Morgan Stanley, Research Division

Yes. I was just going to say -- I was just trying to understand. It sounds like it's a longer-term project as it fits in your portfolio as you -- lots of invested capital and now a 33% interest. Is that kind of the right way to think about when this -- when you're developing here? I know it's obviously past dependent on appraisal information?

Darrell E. Hollek
Former Executive Vice President of Operations

Well, I think all things Bob just gave you are going to be kind of ingredients. That's going to be important to understand. I'd point to Mad Dog, which I believe BP has publicly discussed the fact they're going to take a decision on this year, and they've indicated that sanctioning is likely. And I think there's just a couple of takeaways from that, not necessarily that they're related to Shenandoah. One is they reduced the production solution cost from $20 billion to $8 billion, so that helps with the economics. And two, they think they've got an estimated ultimate recovery that's pretty significant. And so the EUR combined with a lower cost probably gives you a threshold for price that would not have been anticipated a few years ago for sanctioning. So we're hopeful that some of those ingredients will work into our favor as that decision comes to us over the next couple of years.

Operator

And our next question comes from Doug Leggate of Bank of America.

Douglas George Blyth Leggate
BofA Merrill Lynch, Research Division

Al, one of the things, I guess, that makes guidance a little challenging at least in terms of the production outlook, is the tieback schedule, but you've obviously been quite successful in the Gulf of Mexico. I'm just wondering if you could give us some help on relative capital allocation? And I guess the way I would ask the question is what -- on K2 and Constitution in particular, what is the outreach [ph] that you could seek to fill? And what -- how does the relative priority of tiebacks stack up relative to adding capital onshore? I've got a follow-up, please.

R. A. Walker
Chairman & CEO

Well, I think if you go back to our March presentation, the allocation that we laid out at that time gives you a pretty clear understanding. And I think the only thing we would say that would change from that is simply if we find ourselves in an improving oil price environment, which I said earlier I think is very likely, we will deploy that initially for the debt retirement for the maturities in 2017, and then we'll look to the 2 principle onshore assets in the DJ and the Delaware Basins for that capital. That aside, Doug, I can't see any other additional percentage allocation going differently than what we laid out in March, and it's too early to say at this juncture what we'll do for 2017.

Douglas George Blyth Leggate

BofA Merrill Lynch, Research Division

Okay. I appreciate the attempt to the answer. I want a second follow-up, if I may on the Delaware Basin. I know there's been a lot of chatter about whether and if you could ever see an opportunity to acquire your partner's interest there. But if I may, I want to try and ask that question a little differently. Can you give us some color as to what the operated and nonoperated activity looks like? And what I'm really getting at is for the -- how many wells are being proposed by Anadarko versus Shell? And what kind of participation you're getting from your partner? Because my understanding is that you may end up with higher working interest in some of those incremental wells.

R. A. Walker
Chairman & CEO

Well, I'm going to let Darrell fill in some of the details, but that's a question that's really hard to answer, because every package of AFEs that they send to us or we send to them causes that to sort of change the landscape a little bit. We don't have a great insight into what sort of plans they have for developing those wells if they want to push AFEs towards us on. And ours, in terms of what we're planning to do, I think by evidence of the fact we're standing up a few more rigs, speaks to our confidence in the field as well as gives you some insight into what we think the oil prices are going to do. I think beyond that, let me let Darrell fill you in just a little bit more on the details. But philosophically, Doug, I don't think it's likely that our partner there is a seller as best we can tell it. It doesn't seem like they're motivated to do so. And frankly, given the quality of the asset, I can understand that.

Darrell E. Hollek
Former Executive Vice President of Operations

Yes. Doug, probably to follow on with that. From a working interest standpoint, I think assuming a 50-50 is about where we're going to end up, and really are today, I don't see that really changing because of the additional drilling that's going on. I can't speak to the future and the balance of the year, but I can tell you that as today, we got 6 rigs stood up and Shell has 2 rigs stood up.

Douglas George Blyth Leggate
BofA Merrill Lynch, Research Division

So is Shell participating in all the wells that you're putting forward?

Darrell E. Hollek
Former Executive Vice President of Operations

Yes, they are.

Operator

And our next question comes from Charles Meade of Johnson Rice.

Charles Arthur Meade
Johnson Rice & Company, L.L.C., Research Division

I wanted to ask about your view on the A&D marketplace. And specifically, you guys have been very successful selling assets, but at some point, there was also a talk of perhaps buying in the Delaware Basin. So could you talk about what you're seeing on the asset sale side? And what implications that might have for your ability to add in the Delaware Basin?

R. A. Walker
Chairman & CEO

Sure. I think Bob Gwin is probably in the better position to answer that for you. And I'll just say before I pass this to him, I think he and Jerry Windlinger and the folks who have been working that for us over the last several years, particularly in the last 24 months when the market conditions have been pretty challenging, have done an exceptional job. And we often talk about it being a core strength of ours in order of how we manage our A&D portfolio. And how well, I think, we can do it even in times of

challenging and stressful pricing. I know there's been a lot of investor concern that, can you continue to sell assets in a very depressed market? And I couldn't be happier with what I think Bob and Jerry have done in the last couple of years. So, Bob, let me turn it over to you to answer the question specifically.

Robert G. Gwin
President

Okay. Thanks. Charles, it's really a market today where we are buying and selling, but in a lot of small transactions. So it's things that are small enough, they generally don't get reported. The ones that we're summarizing in our asset divesture program are generally our larger transactions. Or in some cases like even recently in the Permian, where we saw some acreage that we had in the portfolio, felt like we wouldn't get to that acreage for quite a while and that it didn't necessarily fit as well relative to our development plans. And so we saw it as a unique opportunity to sell something. I think it's fair to say that the market should continue to be receptive based on the dynamics we're seeing. It should continue to be receptive for the types of assets that we're bringing to market. Those assets share a common characteristic that they're generally not going to attract capital in our portfolio, really at virtually any gas price. And I mention the gas price because they're mostly dry gas assets. We will retain a lot of exposure to gas through the associated gas of our 2 primary U.S. onshore assets. But the dry gas assets have pretty good economics, intrinsic economics that strip pricing. And so we've seen buyers that see it as a -- need assets relative to the size of their firm and the types of things they're trying to do. Not as attractive to us. They make a lot of sense for us to sell. On the margin, we, however, are a buyer of assets. And if they're priced right and if they're in the right location, and really, the 3 core areas where we're putting capital and we believe we have competitive advantages in the Delaware, and in the Wattenberg and in the Gulf of Mexico or places where we continue to look at packages. We look at packages elsewhere, but in many cases, we don't see what our competitive advantage will be or what the synergy is with our existing operations. And so we have not been successful bidders on those packages, where we've chosen to submit a bid.

Charles Arthur Meade
Johnson Rice & Company, L.L.C., Research Division

Got it. That's helpful detail. And then picking up on -- perhaps on that thread of the Wattenberg and the DJ Basin, I want to say it was maybe 1.5 years or 2 years ago that you started the conference call talking about the enigma or the puzzle of what was going on with the California -- or excuse me, the Colorado ballot initiatives. And it's a little different story this time around, but it feels like déjà vu for a lot of people. And the question is -- the question on some people's mind is are we going to be stuck in this kind of loop in Colorado? So can you offer your thoughts on that front and on the political process environment in Colorado? And perhaps if that interacts with your decision or your future decisions to accelerate in the DJ?

R. A. Walker
Chairman & CEO

Okay. Let me make a comment or 2 on that. One is we take what we do in the DJ Basin and Colorado broadly defined very seriously, and we try very hard every day to be a part of educating the electric in the state. We feel like with knowledge of and understanding and appreciation for what the industry does and how we're doing it and the issues associated with what setbacks really mean that an educated voter is more likely to understand why this is important and why the ballot initiative is as structured. Particularly this year, it would do so much damage to the state. We think that's very important. We see both the U.S. senators from the state as well as the governor being very understanding of this issue. In fact, I saw Governor Hickenlooper was on CNBC earlier this morning, and I think he's considered one of the better governors in the United States. And certainly, is very thoughtful around these issues being a part of the oil and gas industry much earlier in his career as a geologist. So I think politically, we have a very good understanding from both a Democratic governor, a Democratic senator and a Republican senator. And I think the politics in the state are such that we just need to continue to do what we can do with the help of other industry participants to educate the voters in a way where when they do go to the ballot, if a ballot were, in fact, on the docket for this fall, that they understand what they're voting on. And we take that very seriously every day as well as Noble and a lot of other companies. And I think to that end, that is the best way I can address your question.

Operator

And our next question comes from Ed Westlake of Credit Suisse.

Edward George Westlake
Crédit Suisse AG, Research Division

I'm intrigued by the schematic that you put in the Delaware this ops report, I mean, 24, 28 wells a section across, obviously, the 3 to 4 different zones. Other companies have done similar stuff. But my question is really around your 2 billion BOE resource number. It seems low versus the number of well locations. And then your net acreage position, so just thinking about is it because this -- some of the acreage is noncore? Is it just a progress on delineation of this large resource and complex geology? And then I have a follow-on.

Darrell E. Hollek
Former Executive Vice President of Operations

Yes, Ed, this is Darrell. I do think that's a conservative number. As we spoke about last quarter, that 2 billion BOE of resource, that's on a net basis. And I think when we look at it and with the amount of BOEs in place for each section, I mean, we're looking at something less than a 5% recovery and we truly feel we'll get a lot more than that. So I do think there's a lot more upside in the numbers that we've reported today.

Edward George Westlake
Crédit Suisse AG, Research Division

Okay. And then, specifically, I guess, on the -- most of the focus has been on the Wolfcamp for the obvious reasons. But on the shallower zones, the Avalon and the second Bone Spring, any sort of indication of sort of EURs that you'd expect from those?

Darrell E. Hollek
Former Executive Vice President of Operations

I think all of those are going to be part of our future plan. When we talked about the resources last quarter, we are only talking about Wolfcamp. And if you think about largely what we're drilling today is down to the Wolfcamp in terms of making sure we retain acreage. We're having to drill down some of the deeper depths. And so we haven't spent as much time on the Avalon and Bone Springs, but I can tell you we're very high on those as well. We think those EURs are still going to be 600-million-plus range in those sections. And so they will be part of our future and part of our future resource, but not quoted in the numbers we're talking today.

Operator

And our next question comes from Ryan Todd of Deutsche Bank.

Ryan M. Todd
Deutsche Bank AG, Research Division

Maybe if I could do one follow-up on capital allocation over the next -- and acceleration over the next couple of years. I appreciate the comments in terms of potential acceleration into 2017. Should we think about -- I mean, how should we think about the balance between capital acceleration and debt pay down or balance sheet repairs? Should we generally just view it as you'll pay down debt as debt maturities progress over the next couple of years? And anything incremental could go into capital acceleration? Or how do you look at acceleration versus balance sheet repair, I guess, over the next 2 to 3 years?

R. A. Walker
Chairman & CEO

Well, let me just reiterate. I mean, what we see today is that the maturities in 2017 and which was approximately $750 million, the monetization proceeds will initially go to that. And then as we see what we believe to be an improving oil price scenario for the reasons I've outlined, then the 2 principal onshore

basins of DJ and Delaware is where we would anticipate if there is good economics, good cash cycling capabilities that we would -- that's where we would put our additional expenditures and additional capital. And maybe with that in terms of just if there's questions around the debt, I'd be happy to let Bob address those. But if there's additional questions on the debt -- is that part of what you're asking me?

Ryan M. Todd
Deutsche Bank AG, Research Division

Yes. I mean, I think the general view is just how should we -- I mean, I think you have a longer-term target to get to -- to get back to kind of a 30% debt-to-cap ratio, I believe. And so how do you think about -- as you look forward over the next few years, and I get that this is highly dependent on oil price as well, but how do you think about your ability to accelerate versus a desire to eventually kind of get the balance sheet back into the kind of long-term target ranges?

Robert G. Gwin
President

Well, we use a variety of metrics beyond just debt to cap. And debt to cap is somewhat less relevant. The oil targets are somewhat less relevant. Given that with the way the commodity prices have backed up, we and everyone else have taken a lot of write-downs of assets on the balanced sheet that have affected that -- what that debt-to-cap number might look like in the future. But when you look at debt to cash flow in particular and we look at debt per barrel and producing barrel, it is -- we feel that the balance sheet is not that far out of whack of where we'd like for it to be. The difference versus the past is that we don't expect a commodity price recovery to, I don't know, $90, $100, or whatever we were facing at a point in time when debt-to-EBITDA metrics across the industry were so much lower. And so the way we're looking at it is to try to have -- try to match our pro forma metrics to our pro forma activity levels and that pro forma commodity price, as Al mentioned, where we go back to work. So it's a bit of a moving target. And now what we know with certainly we'll do is take -- is repay the $750 million of debt that we've stated publicly repeatedly that we are going to repay of the 2017 maturities. And we believe that there should be an opportunity to reduce gross debt further through some liability management programs around many of our smaller less liquid issues. But in many cases, the holders are very happy with those issues, and we certainly wouldn't expect to pay a material premium just to retire them. We do have a put bond out there that is not callable, but it's puttable to us once a year. Certainly, there, you can negotiate around some of that type of debt, if we wanted to take our gross debt number down further. But it's our clear intent, as we've stated in the past, to continue to build cash and to ensure that we're reducing that net debt number, that we continue to remain focused on liquidity, and we're very comfortable that the liquidity position, the leverage position allows us to accelerate drilling should the commodity price warranted. But to accelerate within reason. We're talking within the hundreds of millions of dollars, not massive changes of outspending cash flow. We're pretty close even at current discretionary cash flow to spending within discretionary cash flow. So the delta here is asset sales. If we're successful with asset sales the way we have been, then it gives us a lot of flexibility based on the commodity environment and outlook that we see at the time to moderately reduce leverage, consistent with that commodity price environment and to moderately accelerate spending in places where we have really attractive returns to begin to move our production back toward growth and away from maintenance.

Ryan M. Todd
Deutsche Bank AG, Research Division

That's very helpful. I appreciate all the detail on that. Maybe if I could follow up on some of the -- on the previous question on the Delaware Basin. We've seen great results out of you guys across the Wolfcamp and you had 11,000, 10,000 foot long laterals, I think, in the Wolfcamp that you brought on so far. Can you talk a little bit about what you're -- how much running room you think you have in terms of acreage that's conducive to 10,000 foot laterals? And then maybe as a follow-up to that as well on the second Bone Springs and the Avalon, any rough estimates as to how much of your acreage that those horizons might be prevalent across?

Darrell E. Hollek
Former Executive Vice President of Operations

Well, let me just start with -- our focus is clearly going to be the Wolfcamp. And we've got -- a lot of our acreage is conducive to at least mids, and in many cases, longs, but surely not all of it. And we'll continue to look at ways in which we can show [ph] our trade acreage and build that land position such that we can go with the longer laterals. But I think what you've seen over time is we started with many of the shorts, and today, our average is closer to the mids only because we've been able to do a number of longs, some mids and some shorts. And so clearly, it's beneficial for us to do the longer laterals where we can, and we're looking at every opportunity where we can, like I said, trade acreage maybe such that we can get in that position. As far as Avalon and Bone Springs, again, I just reiterate, we're not focused on that as much right now. We've done some Bone Springs, but clearly, our prize is the Wolfcamp today. And whatever land position we create ourselves for the Wolfcamp, we'll get the benefit in both Avalon and Bone Springs.

Operator

And our next question comes from Brian Singer of Goldman Sachs.

Brian Arthur Singer
Goldman Sachs Group Inc., Research Division

I wanted to follow up on some of the Wolfcamp question here. Can you just give us a bit of a lay of the land on how pervasive over your acreage is the 12 wells per section from a development perspective? Are there areas that aren't perspective or are perspective at fewer than 12 wells per section? And then in the lower Wolfcamp, what's the timing and the potential aerial significance from the testing that's currently ongoing?

Darrell E. Hollek
Former Executive Vice President of Operations

Yes. Brian, this Darrell again. As we look at it today -- and understand that a lot of the drilling we're doing is to make sure we understand our entire acreage position. But if we -- if I had to give you a number today, I'd say at least 3/4 of our Wolfcamp position is what we would consider Tier 1 and would have at least 12 wells per section. I mean, some of that's going to be driven by economics. And so as prices go up, we may find ourselves with a lot more wells in those sections beyond the 12, because you understand there's many benches inside the Wolfcamp. So as demonstrated on that 1 sheet, we're basically talking 4 wells per bench, but it clearly could be more than that.

Brian Arthur Singer
Goldman Sachs Group Inc., Research Division

Great. And the Lower Wolfcamp testing, how aerially significant would that be? And what's the timing there?

Darrell E. Hollek
Former Executive Vice President of Operations

In the case of the Lower, it's not as nearly prolific as what we see as the Wolfcamp A. But again, we hadn't done as much testing there, but clearly, it's going to be one of our targets in the future as well. But if you look at the Wolfcamp A in our case, we've got many benches in there, so it's our primary target.

Brian Arthur Singer
Goldman Sachs Group Inc., Research Division

Great. And Al, you highlighted your optimism for oil prices next year and your hope and interest in bringing back activity. Can you talk more specifically about what you're looking for to make that decision to bring production back on? How much of it would be based on your own projections for commodity prices versus either real-time inventories? What the forward curve is saying or the front-month price, particularly given the lead time until you actually see that production come on for pad drilling?

R. A. Walker
Chairman & CEO

Well, I'll give you my thoughts, Brian, on that. And that's simply, as we see U.S. oil production cascading towards that 8 million barrels a day that I made reference to in terms of where I think it will bottom out before it starts to go back up, that will, in my estimation, help a lot. And if we -- on the demand side, we continue to see 1.2 million to 1.4 million barrels per day of demand per annum through the balance of the decade, I think the combination of the 2 are quite significant. It's been our view that we will see this be a price recovery when it's demand-driven, but rather than supply constrained. Market forces don't work real well when you're relying on supply constraints to drive price. But I think if you think about it as a demand function that improves annually at the clip of 1.2 million to 1.3 million barrels a day, you can see pretty quickly that in an expanding demand relative to the supply, demand is going to move up the curve and the intersection that creates P will put pressure on prices to move up to a level of around $60 a barrel. After that point, I mean, we're going to have to see what happens from a, a demand standpoint; b, from a cost, are we going to see margin erosion? Are there returns in the cycling characteristics that we particularly follow with our onshore investing? Are they still going to be as attractive as we thought? So I'm not going to go beyond $60, but I think clearly in our estimation, the ingredients are there for recovery to sustain $60 price environment for next year. And I've probably been as big a bear around oil expectations as anyone since early 2015. And I think with this, if we continue to see the characteristics I just laid out, continue to be prevalent in the market, that will be a great indication to us for what we want to do. Looking at the forward curve, I think you know as well as I do that's a little fragile. And as you look out further, particularly in light of our -- the world we live in today and the lack of players in the market for the forward curve, it looks flat for a reason because we don't have the same participants in the curve today that we had 5 years or certainly 10 years ago. So the curve itself probably is not going to be as much of an indicator of activity as the other things I just made reference to.

Operator

And our next question comes from David Tameron of Wells Fargo.

David Robert Tameron
Wells Fargo Securities, LLC, Research Division

Al, can I just go back to that $60 number? You had previously said margins were kind of what drive your decision. So can you talk about if we're in the $60, would you expect service cost to close that gap on the margin? Or how should we think about that dynamic?

R. A. Walker
Chairman & CEO

Yes. David, I may very well be wrong, but I don't see from, call it, $43 today to $60 a lot of service cost price inflation. I do think as we approach $60, we'll start to see it, depending upon the activity in the principal basins that would be driving our U.S. oil price -- our U.S. production. We're just continuing, I think, as an industry, to see price concessions on service cost today. I think it will take a while for activity levels and the use of services to put a lot of pressure on having service costs go up. At some point, service costs will go up. But I think as you think about it and the way I think about it from a margin perspective, we don't anticipate a lot of wellhead margin erosion between here and $60.

David Robert Tameron
Wells Fargo Securities, LLC, Research Division

Okay. That's helpful. Coming back to the Delaware. One of the concerns, I guess, has been capacity and constraints and ability to get production on the basin. I look at your numbers and looks like you exited at a higher rate than you averaged for the quarter. Can you just talk about how much running room as far as just pipeline capacity and takeaway in infrastructure of debt limits? And I'm just thinking later this year if oil heads back to $60, how much more room do you have to allocate into the Delaware?

Darrell E. Hollek
Former Executive Vice President of Operations

David, this is Darrell. At this point, we see no constraints. We haven't seen a sign of it, and we don't expect to. I think there's a lot of systems being built out. I know inside WES, we're expanding our capacity every day. So we don't see that to be a problem anytime soon.

Operator

And our next question comes from Paul Sankey of Wolfe Research.

Paul Benedict Sankey
Wolfe Research, LLC

Al, just pulling together everything that we've just heard. Firstly on the 8 million barrels a day that you see the U.S. production level reaching, what's the time frame for that? And the follow-up is, it feels and looks very much from this result as if you're balanced now cash flow CapEx with flat volumes at around $45 to $50 a barrel. Firstly, if we do go lower than that, do -- is there more to do or do we simply restart raising debt? And secondly, if we progress as you anticipate from $45 today-ish to $60, is that move then a debt pay down move until you restart growth at $60? Or is there sort of a progression in that?

R. A. Walker
Chairman & CEO

You bet. Well, let me try to take those as best I can. It's -- the timing for 8 million barrels a day, I'm no better at projecting that than -- a lot of people are paid money just to do that by themselves in the vacuum of their own thoughts. But our view is that it could happen as early as late this year. And that's why we made -- I made the comment earlier, we think it's likely that we could see a sustained price environment of $60 developing later this year. Now for reasons that I can't quite explain, but it takes a little bit longer to get to 8 million. That could be pushed into 2017, but you know better than I do how capital intensive our industry is, particularly for unconventional development and the sustaining of production levels. And we, as an industry, have not been investing at a level that allows production to be held flat. Just exactly how fast it cascades is sort of the question I think each of us need to watch. But my comment to you would be I think it could be as early as the fourth quarter, and that's the basis by which I'm making my comments. Because I still see the demand side using IEA as the basis for that with having 1 million to 2 million, maybe 1.2 million to 1.4 million barrels per annum of additional demand. It will be a demand recovery, not a supply recovery. And it's really the basis of that demand expansion or the large and increasing portion of the pie, that I think will give us some comfort around how that actually will be sustained. As it relates to capital planning, you're right. This is not a step function. It's not linear and it's probably more likely logarithmic. As we approach $60, we'll invest more than we will at $43-ish and in terms of where WTI is today. So we're already sort of telling you today that we anticipate with improvements that we think are forecasted, that we will start to reallocate some of our monetization proceeds as we've described on this call. I think if we -- as we get into our planning for capital for next year and think about that in conjunction with the discussions with our board, the more we feel comfortable about that sustained $60 price environment, the more likely you will see us increase in capital, particularly in the areas that we're talking about on the margin, increasing capital to -- in anticipation of a price recovery. I hope that helps. You had a question about -- I'm sorry, you had a question about debt. Let me let Bob answer that.

Robert G. Gwin
President

I guess, Paul, there's one thing I want to point out though is you asked if prices move the other way, if we're wrong and prices go down, does that mean we increase debt? Absolutely not. In fact, we continue to reduce debt through the asset monetization proceeds. So prices go down, the asset monetization proceeds go to debt reduction. As prices go up, we first reduce the debt along the lines I described earlier, and then we start to put the dollars back to work the way Al just described.

Paul Benedict Sankey
Wolfe Research, LLC

Helpful. And then the follow-up -- the obvious follow-up is just can you talk about hedging and all that?

Robert G. Gwin
President

We've -- as you guys saw on some of the information, we've layered in some gas hedges. I think if you look at the structure, there's 3-way collars. It starts to inform us to our views on natural gas, which are not particularly bullish. But we think we've left ourselves some upside to benefit, in particular, with our associated gas production. That remains a pretty significant part of the portfolio. We have not focused on layering any oil hedges. We don't like the structure of the market today to go ahead and lock in prices at all. And we've never looked at hedging as a way to justify drilling activity at any given price. We've instead looked at hedges as a way of providing some moderate protection to the balance sheet and reducing the volatility of our cash flows relative to the commodity price environment. So we've -- as we've done historically, we'd probably like to layer in some oil hedges at the right price when we like the shape of the curve. And I think from a gas standpoint, whether we do anymore or not just also remains to be seen. We're pretty comfortable with what we've got done for '17 at this stage.

Operator

And our next question comes from John Herrlin of Societe Generale.

John Powell Herrlin
Societe Generale Cross Asset Research

Just some unrelated ones. You added a new board member, what was the rationale there, Al?

R. A. Walker
Chairman & CEO

Well, you are one of those people who watches everything, so I really do appreciate that about you. Sometimes we put press releases out, you wonder if people look at them in any detail. So thanks for the question. Yes, we really felt like adding someone like David Constable to our board was very important for his skill set. Dave has got a long career at Fluor and then later at Sasol. With big project management, understanding how big boxes need to be built and how the project management needs to be executed, I think his experience will be quite helpful as we approach and consider the day when we take FID in Mozambique. And he'll also be a wonderful board member for management to be able to go to and use as a resource as we consider that decision. So not to say that we don't have board members today that are helpful in that area, we do. But we recognize the challenges associated with taking FID in Mozambique are fairly significant. And being able to add a board member like David with his skill set, we're very, very fortunate to be able to do that. And thank you, John, for asking the question.

John Powell Herrlin
Societe Generale Cross Asset Research

Okay. My next one, Al, I appreciate everything you said about margins, but the services companies last week, the big ones that reported were all pining about the need for higher revenues for their offerings. How much of your savings, especially onshore, do you think will be sustained because of the change in process and design going forward?

R. A. Walker
Chairman & CEO

Well, I'm going to take this in part with Darrell, because some of the process changes are going to be able for -- are going to be such that we can retain some of the efficiencies that we have today. In certain fields, it's going to be very high such as in the Delaware -- I mean, the DJ Basin. But I think what we're seeing, John, is that it's still a fairly aggressive service environment for what the service providers need and want in the way of market share. And we've got a new participant back in that market, given the unsuccessful consolidation of Halliburton and Baker Hughes. And I think you just have to appreciate in the near term; that is the new dynamic into the marketplace that was not there earlier this year. And Darrell with that, why don't you please take it to the next step?

Darrell E. Hollek

Former Executive Vice President of Operations

Yes. John, if I had to guess, I would say we're going to at least maintain 2/3 of what we've been able to achieve. If you just recall of what we've gone through almost every quarter, as we continuously are finding more efficient ways to drill and complete these wells. And even the facilities side, we're getting better at that. And so no doubt, the cost structure coming down has helped, but our efficiencies has probably been the biggest driver. And with that, I would say that just because we're here today, it doesn't mean we won't continue to find different ways to increase our efficiencies and what we're doing to help offset any pressure we may see going forward.

Operator

And our next question comes from Arun Jayaram of JPMorgan.

Arun Jayaram
JP Morgan Chase & Co, Research Division

I was wondering if you guys could give us an update on the TEN project in Ghana as well as maybe some of your gross volume expectations for '16 and '17? And any potential impacts from development from the border dispute?

James J. Kleckner
Former Executive Vice President of International and Deepwater Operations

Yes, Arun, this is Jim. As you've seen in the public release on the TEN project, they are about 97% complete with the hook up and commissioning of all aspects of the TEN development. The project is progressing very well and initial production should begin early in the third quarter. It's anticipated that the field will be brought online and start sequencing commissioning of water injection and production operations and ramp throughout the second half of the year. So we see the TEN project on schedule and meeting expectations.

Arun Jayaram
JP Morgan Chase & Co, Research Division

And Jim, just the kind of the volume expectations that you expect in the back half and in '17, just from a growth standpoint?

James J. Kleckner
Former Executive Vice President of International and Deepwater Operations

Well, I think the TEN production volumes will ramp up as the operator has stated. And it's going to be a slow initiation of that production as they first bring on Enyenra field and then the Ntomme field and followed up by the Tweneboa field later on. So we'll have to see how that ramp up in production goes.

Arun Jayaram
JP Morgan Chase & Co, Research Division

Okay. Fair enough. My second question is just regarding -- wondering if you guys could provide a bit of color on DUCs versus iDUCs? I know looking at the ops report, you tied in 40 wells in the Eagle Ford. And then in the first half of the year, you've been running 1.5 rigs and tied in about 137 wells in the Wattenberg. I'm just trying to understand if you could help us delineate between DCUs versus iDUCs? And where your iDUC balance stands today?

R. A. Walker
Chairman & CEO

Arun, are you telling you didn't go look up in the standard Webster's Dictionary the difference in those 2?

Arun Jayaram
JP Morgan Chase & Co, Research Division

I know it's given Colglazier a lot of fun, iDUCs versus DUCs.

R. A. Walker
Chairman & CEO

Yes. Well, yes. At some point, Webster's will include it in their dictionary, I guess. But for now, I understand the questions. Let me turn it over to Darrell, all being jocular aside.

Darrell E. Hollek
Former Executive Vice President of Operations

Yes, Arun. We would quote [ph] these iDUCs and I think we came into the year with about 230, and I would argue we still have roughly the same. You look at something to your point at Maverick, a lot of that had to do and it was more of a cost-saving measure and a lot of this was done actually in '15. We took the opportunity to tie back to some of the existing equipment as opposed to building new, and so some of that got delayed, and that's what you're seeing there. It really didn't affect our numbers. But I think from a practical standpoint to address your issue on iDUCs, we've got other wells that we usually have in the queue in terms of their drilled and uncompleted. And so we have probably in excess of 500 wells like that. And so I think from a practical standpoint, as Al was suggesting, as we look forward into the end of the year and into next year and we have the opportunity to stand up rigs and additional crews, you will see that all of that really becomes the inventory in which we'll work off of. And in some cases, it has to do with simultaneous operations. Some of it -- it's going to have to do with what we want to test, so that we can run additional information in places like the Delaware. And so I think -- again, looking forward, I would just look at it from a standpoint, we've got about 500 wells in inventory like that, that we'll be using as we increase our programs going forward.

Operator

Our next question comes from Matt Portillo of TPH.

Matthew Merrel Portillo
Tudor, Pickering, Holt & Co. Securities, Inc., Research Division

Just 2 quick questions on the Delaware Basin. First, just wanted to talk a little bit about the completion design change. You guys have made fairly significant strides in optimization since 2014. And I was wondering if you could talk about from a high level perspective the impact of your expectations from an EUR perspective within the Wolfcamp. I think the last kind of full summ update we saw was really around early 2015. And then there were some discussion in the press releases around that EUR progressing higher late last year, but just curious around the current design and thoughts on the rate of change on the EUR side?

Darrell E. Hollek
Former Executive Vice President of Operations

Yes. Matt, I'd say it's fair to say we have made a lot of improvements. But I'll tell you, we're learning all the time. We're in the midst right now of a 20-well test, if you will. All-in-one particular area, where again the reason for the test is more for the completions and the drilling side of it. And so we still have a lot to learn. But as we vary some of these stages, some of the sand, we're pumping, even some of the water we're pumping in these intervals, we're learning all the time. But I think it is fair to say as we've got additional production data, we do feel the EURs continue to increase. And so as I pointed out last year, a lot of these wells that have been online now for a while, we're seeing 800,000 to 1 million barrels of oil. So we're feeling really good about that. But there's still a lot to learn. And understand, we've got a huge acreage position, so we're going to see some variance across this as well.

Matthew Merrel Portillo
Tudor, Pickering, Holt & Co. Securities, Inc., Research Division

Great. And then just a follow-up question in regards to the Avalon. I was wondering if you could talk about the growth column that you see perspective? Where you delineated that so far? And if there's any current plans this year to further delineate the play potentially with higher intensity fracs?

Darrell E. Hollek

Former Executive Vice President of Operations

As far as Avalon, you won't see us doing any more work on that this year to my earlier point. In a lot of cases, where we're preserving our leases, we've got to really drill down to the Wolfcamp, and that's really our big prize. What we've seen in the past is these wells are sort of on the order of 1,500 BOE per day wells, 800 million -- or 800,000 barrel [ph] EUR. So we think this really going to be a productive area, but you're just not going to see us playing it anytime soon.

Operator

And our next question comes from James Sullivan of Alembic Global Advisors.

James Jan Sullivan
Alembic Global Advisors

Just a quick modeling one. You guys have obviously talked about Tullow's plan to permanently moor the Jubilee, and I guess that's a '17 project. I think you guys talked about deferring some El Merk maintenance into '17 as well. You're deferring it from this year. Can you guys quantify at all the impact to -- your international oil from those 2 pieces of maintenance happening maybe at the same time sometime in '17?

John M. Colglazier
Investor Relations Professional

Yes, we're still -- this is Colglazier. We're still working to our 2017 guidance levels based upon incorporating the information we got from Tullow on the timing of Jubilee, et cetera. You'll have the ramp up, as TEN as Jim just talked about. And at El Merk, reevaluating the timing on when we need to do that turnaround. But I think if you look at what happened this year, I think the aspect of both the U.S. onshore, offshore and Algeria have largely offset the entire impact we've seen from Ghana, which is pretty darn amazing. So when we look at our aggregate crude production, we're still going to be relatively flat on a divestiture adjusted basis, both on a full year average as well as an extra grade. When we move into next year, I think we're pretty well situated. And that only improves if we allocate incremental capital to our growth plays in the U.S.

James Jan Sullivan
Alembic Global Advisors

Okay, great. I appreciate that. Just another one, it's sort of a strange question. But when you guys talked about the tieback opportunities that you have in the Gulf of Mexico, you guys gave us a couple of different cuts on the capital program. You do it by area, but then also between base maintenance and the different cycle time projects. When you guys think about the tiebacks, do you categorize those as base maintenance or as development work?

John M. Colglazier
Investor Relations Professional

It's embedded in our maintenance capital because we need the volume contributions from those to help maintain our aggregate volume levels.

Operator

And our next question comes from Jon Wolff of Jefferies.

Jonathan Douglas Wolff
Jefferies LLC, Research Division

I saw they brought in a lot of wells in Maverick Basin and Eagle Ford in the second quarter, but no drilling activity. I'm wondering -- thoughts around that asset versus maybe fairly flat. And then maybe the same question around Northern Louisiana

[indiscernible] activity levels are fairly low. Any thoughts around the train [ph] of those assets as you see them longer term in the portfolio?

R. A. Walker
Chairman & CEO

Jon, this is Al. I'll take part of it and let Darrell take part of it. Good question, good observation. I think as it relates to Maverick right now, as we think about it from a portfolio standpoint, Maverick Basin and the Eagleford Shale, I think from [indiscernible] capital as well as the other 2 principal basins we've been talking about this morning. It doesn't mean that it doesn't create attractive rates of return. It's just unfortunately, it's up against 2 exceptional assets that create better rates of return. And for a company that's trying to stay close to or on top of discretionary cash flow and CapEx, it just -- unfortunately as a result of that doesn't feed on capital and constantly is not being allocated capital, and so that would be the takeaway there. Darrell?

Darrell E. Hollek
Former Executive Vice President of Operations

Yes. Jon, again the only comment I'd make is we did complete some wells in the third quarter. But the bulk of them were actually completed last year. And the reason they came on in the first and second quarter, a lot of that had to do with trying to tie back into existing infrastructures as opposed to building [indiscernible] new few wells. So it got delayed a little bit. But if you look at us today, we have no rigs, no completion.
[Audio Gap]

Exhibit 113

THOMSON REUTERS STREETEVENTS

EDITED TRANSCRIPT

APC - Anadarko Petroleum Corp at EnerCom Oil & Gas Conference

EVENT DATE/TIME: AUGUST 16, 2016 / 8:45PM GMT

THOMSON REUTERS

CORPORATE PARTICIPANTS

Brad Holly *Anadarko Petroleum Company - SVP Operations - Rockies*

PRESENTATION

Unidentified Participant

The next presenting Company is Anadarko Petroleum. Anadarko was formed in 1959 as a subsidiary of Panhandle Eastern Pipeline Company. In 1985, it was spun into a standalone company, a stand-alone independent company.

Through multiple acquisitions, Anadarko has grown into one of the largest independent oil and gas companies in the US, with average second-quarter production of 792,000 BOE per day. The Company entered Colorado in the year 2000 with its acquisition of Union Pacific Resources.

Please join me in welcoming Brad Holly, SVP of Operations for Anadarko's Rocky Mountain region.

Brad Holly - *Anadarko Petroleum Company - SVP Operations - Rockies*

All right. Well, thank you and thank you for being here today; thanks for your interest in Anadarko. I look forward to talking a little bit about our financial situation as well as running you through our worldwide asset portfolio.

Our objective in 2016 has been to successfully navigate through this challenging environment. We believe we've taken the right actions at the right time to preserve and enhance value versus growth.

We have tried to preserve and enhance that value by what you've seen on there. We reduced our capital program over 50% year-over-year; 70% since 2014. Reduced our dividend, which saved about $450 million of cash.

And we've achieved incredible cost savings and efficiency gains through what we've done. Had a very aggressive monetization program that I'll walk you through, and we've really been focused on building cash and reducing our debt, working on our credit story.

Our global footprint provides a tremendous amount of flexibility in our best-in-class portfolio that we have. You'll see on the bottom there that we're spending 40% plus of our capital on more long-dated projects in order to set us up for -- as we emerge from this current commodity environment.

If you look at our targets for this year, you can see our original projection up there. When we adjust that for divestitures, we are still moving guidance up by 2 million barrels. You can see that our capital program is anywhere from $2.6 million to $2.8 million, and we've announced $2.5 billion of monetizations, with line of sight to be at $3.5 billion by the end of the year.

So philosophically, to manage in this down-cycle we've employed thoughtful capital allocation, responsible fiscal discipline, and peer-leading portfolio management. We'll deliver flat oil production this year and maybe, more importantly, fourth-quarter to fourth-quarter oil production will be flat. So the decline that you see is low-margin gas pretty much for that entire thing. This portfolio mix provides cash flow in excess of our CapEx due to these aggressive monetizations.

When we look at the Anadarko history you can see here the last six years. We've consistently created more cash flow than we've spent, the green bars being our adjusted discounted cash flow and the blue bars being the capital. We generate about $14 billion of free cash flow in this time period.

You can see as we look to 2016, you can see the monetizations there that make a big difference. So again we've talked through those things.

We're improving our credit story without reducing our equity story. We're investing within cash flows, and we're focusing on net debt reduction. We're doing that several ways: first, cash flow through operations; reducing our CapEx; proceeds from the monetizations; and lower expenses.

One of our big goals is to maintain our financial strength. You can see that we have ample liquidity on hand with cash on hand and then a couple of facilities there.

Earlier this year, we went out with a $3 billion bond offering. It was subscribed at -- exceeded $20 billion. So we were able to issue new debt at rates lower than the debt that's maturing.

So we moved out a lot of that, and we've announced and agreed to retire $750 million; that's planned 2016 retirement. So that gets all of our near-term retirements out of the way.

It's very important with our portfolio and worldwide nature to be investment grade. We feel like we are investment grade, and we're pleased with S&P and Fitch's comments on that.

Let's turn from the balance sheet and the financials to our portfolio, and let's walk through this. The US onshore represents about 75% of our current production. You can see that we've taken capital down significantly here, about 70% year-over-year, and really focused on the base production.

You can see that while we've cut capital significantly, our volumes are very close to where they were in 2015. That's a lot of great work on optimizing the base. When you have 1,000 horizontal wells and you can make small tweaks and upgrades to each and every one, you can have a big effect on that.

So we're really focused now with our $1.2 billion of capital in two assets: the DJ Basin and the Delaware Basin. And I'll walk you through both of those on their separate slides.

As we look at the DJ Basin, that has just been a world-class asset. It's the only asset that I can remember in my history working that, if you look at the cash flow and the capital on the bottom left-hand side, every year we have exceeded our CapEx investment with future -- with cash flow coming out of the asset. So it continues to do that, and 2016 is probably our max delta that we've had between cash in and cash flow out.

This is a 1.5 billion barrel asset. We've drilled about 1,000 horizontal wells and we have 4,000 left to drill.

We see some distinct differential advantage in the DJ Basin. One is our mineral interest ownership that we have underlying this field and every other section, where we own the minerals. The second is an expanded and controlled infrastructure through WES, that has two cryo plants as well as a gathering system and compression in the field, that helps us lower the line pressure and produce these wells; and then really our consolidated acreage position. You see our concentration there, and by having that concentrated position we're able to more efficiently develop our program.

You can see that our capital costs are down to about $2.4 million a well now in the DJ Basin, which gives us a breakeven of about $30 a barrel. So we have taken this down to one rig right now. We've reduced activity to preserve this value for a better day.

A lot of our onshore focus right now is in the Delaware. We have almost a 600,000-acre gross position here in Loving County and out into Reeves County.

We just doubled our net resource to 2 billion barrels, and that is all of the Wolfcamp A. So that reserve number is tied to one zone.

We have 10,000 foot of stacked pay out there. We have 10 plus zones other than the Wolfcamp A that we are currently exploring and delineating and applying science to, to see how big this field can get. So while we see the DJ as a world-class asset, this one will likely take our Company into a new realm and be larger than any other onshore play that we've ever had.

You can see that the cost side was really important to us. 2014, we were almost $12 million a well and we've driven that down to $5 million a well; and once we get on pad drilling we think that another $1 million will come out at that point.

So we're seeing almost 1 million -- we're seeing EURs approach 1 million barrels a well, and in this play we've got a breakeven down to $35 a barrel here. Six rigs running and we're working on understanding the field better as well as some lease preservation.

Moving offshore to the Gulf, we think that this is probably an underappreciated plank in our platform. We think, though, our Gulf of Mexico assets underscores the value of conventional resources. So while you have the unconventional resources that come on with high IPs and decline very rapidly, you've got something very different going on in the Gulf of Mexico.

We have the most operated deepwater platforms of any operator in the Gulf of Mexico today. We feel like using that infrastructure for subsea tiebacks is a very economical venture.

In approximately six months, we can bring on 20 to 25 million-barrel wells at a very low development cost, and so we're trying to use our infrastructure to keep production flat and to move that through. A couple of examples there, if you can see that.

Our Constitution platform that we have a 100% working interest in, we set about 10 years ago. We produced Constitution through that, and then we produced Ticonderoga through that, and we are currently producing Caesar/Tonga back through the Constitution platform. You can see that through the rest of the decade we plan to have flat to increasing production off of the Constitution spar out there.

Lucius has just been a great success story. We found probably the best rock we've ever found in the Gulf of Mexico here: 300 million cubic feet -- or 300 million barrel field that's economic down to $20 a barrel in that. Because of the financial arrangements we did there, that facility will actually pay out this quarter, and you can see that we're just getting started.

Another great advantage of the Gulf of Mexico that you can see with that red wedge there is we bring another non-op, Hadrian South, through our platform there. That platform or spar is producing above nameplate capacity, and again we think it will stay flat for many years to come.

Heidelberg was brought on this year. Again, that was our design one, build two program. It came on about 18 months ahead of schedule, and we are currently drilling a couple more wells in Heidelberg that we expect to add 8,000 to 10,000, 12,000 barrels additional per well.

So Heidelberg will continue to be ramping up. And then in the out-years we'll be looking for additional tiebacks.

So we like the Gulf of Mexico for a lot of reasons. We think it's differential to Anadarko.

One, we've had doubled the industry success rate in the Gulf of Mexico. Our ability to find oil has about a 60% success rate.

When we design facilities and design production, we're generally about 40% ahead of the curve on timing and on capital. And we combine those with some infrastructure that we already have out there, we think that it's a very compelling case for us.

Moving a little farther away in our international arena, a couple of conventional assets that are really performing well for us, Ghana and Algeria. We're pleased with the operator of Jubilee and the conclusions that they have come to spread more of that FPSO. We expect to continue to produce Jubilee around the 100,000 barrel of oil gross basis.

The TEN complex will come on this quarter -- this month, in fact. So we'll have our second FPSO in Ghana moving forward.

Algeria continues to produce well for us. What we have here is we have very high-margin oil, we have very low declines, and it takes very little maintenance capital. We're talking under $90 million between both of these on an annual basis to keep those oil flowing.

Mozambique, truly one of the best gas discoveries in the last 20 years, has an opportunity to be a world-class LNG field. It changes the Company as well as changes the country, and we're moving forward with that.

We started with 100% of Mozambique. We've sold our way down to 26.5% working interest currently, so we are cash positive on this play to date.

We're working very hard on the legal and contractual framework with the government to continue to move that forward. That will be the critical path item and where we are working forward there.

We're also working on offtake agreements as well as project financing. We're putting minimal capital into this asset right now until we get that legal and contractual framework together. Once that's together, when we have some certainty around that, we'll move forward to FID of this project.

We're also fairly focused on our international and deepwater exploration. What we're currently doing there is we're in CI and on 1 million acres there. We've got the Paon well that we're actually DST-ing currently. Once that DST is complete, we'll drill two more exploration wells.

You see Pelican and Rossignol will be our next two wells there. Then that rig will move over to Colombia. I'd just point out on Colombia that 16 million gross acres, which is about 10 times the acreage that we currently have in the Gulf of Mexico.

It's a huge position that we've drilled one exploration well. We will come back and drill another exploration well. We're currently shooting a very, very large 3D seismic acquisition over that area, and we're excited about that very large position and what it might hold in the future for us.

In the Gulf of Mexico, we just finished our Shenandoah-5 well. Again, over 1,000 feet of pay in that well.

It extended the limits of the field. We did not find the oil-water contact.

The partnership is excited about Shenandoah. We'll go back out in the fourth quarter of 2016 to drill Shenandoah-6; and so expect an update maybe mid next year as we get the results of that.

The other two that you see on there are subsea tiebacks that I was talking about earlier: the Phobos back to Lucius and Warrior would go back to the Marco Polo TLP.

So again, that's our exploration program. If you look at just a lookback -- and we hope that the lookback is an indication of going forward -- we spent about or we invested about $10 billion in exploration. We found about 6 5 billion barrels. We've monetized 1.4 times what we've spent, and then we have about 5 billion barrels left to develop.

That exploration program is currently producing about 250,000 BOE per day from that program. So we feel that exploration is a key component of our portfolio and continues to differentiate. You can see on the bottom the things that we are currently exploring that I went through, the things that we are appraising, and the development to continue to drive value into our system.

So finally, I'll just close with this. We are working on successfully navigating a very volatile environment. We will do that by maintaining our financial discipline and investing within cash flows.

We will continue to focus on the value. We'll reduce capital spend and cost structure as we need, to stay within that cash flow.

We feel like we have a very active portfolio management, and we've got a world-class portfolio. So we'll continue to be flexible and move money around the globe where we think it makes the most sense.

We will continue to actively monetize noncore assets and really focus our US onshore play on the Delaware and the DJ; and we'll focus our Gulf of Mexico play around our current facilities for subsea tiebacks; and then we'll focus exploration as you saw in CI and Colombia.

So we feel like that we've improved our balance sheet this year. We have a strong credit story.

We like the mix of the conventional and the unconventional asset base. We think that makes us less capital intensive and well positions us during the downturn.

We are positioning the Company to come out of this downturn with abundant liquidity to safeguard against future volatility. We expect exceptional operating results and flexible deployment of our capital, and we'll continue to invest in our future with mid- and long-cycle projects to take advantage of the market conditions when they change.

So with that, I think we'll be happy to move rooms and take any questions that you might have.

Exhibit 114

S&P Global
Market Intelligence

Anadarko Petroleum Corporation
NYSE:APC
Company Conference Presentation

Wednesday, September 14, 2016 4:00 PM GMT

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Call Participants

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Robert G. Gwin
President

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Senior Vice President of Midstream

ANALYSTS

Unknown Analyst

William A. Anthony Featherston
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William A. Anthony Featherston
UBS Investment Bank, Research Division

Our next presentation. Terrific timing to have Anadarko Petroleum here today in the wake of their deepwater transaction announced earlier this week. And here to tell us about it is Bob Gwin. Bob is Executive VP and CFO. And of course, most of you know, John Colglazier and Robert Fielder from IR. With that, I'll hand it off to Bob.

Robert G. Gwin
President

Bill, thanks. You're right, timing really couldn't be better, and we very much appreciate you guys listen to the story again today. Many of you, I hope, were able to join for our conference call that we did at about 8 a.m. yesterday morning. And if so, I -- if you were able to join, I apologize, we're going to cover the same slides here that were on the website that we kind of spoke to yesterday. We're going to do so fairly quickly though with an eye towards maximum time for Q&A.

Just to touch on the transaction highlights we've got, it's a $2 billion acquisition of the deepwater Gulf of Mexico properties of Freeport. We've got about $1.7 billion of value ascribed to the properties themselves, about $300 million ascribed to the, what we're calling, materials inventory along with some seismic. The materials inventory, obviously, is going to be used in the development of the resources that we're acquiring.

You see some of the -- on this slide, Slide 3, you see some of the metrics of the deal. It's highly accretive. We equity financed the transaction and even fully equity financed -- it's about 25% accretive to cash flow per debt-adjusted share this year, about 30% next year. The economics are really phenomenal. It starts with a very attractive purchase price relative to the cash flow of 1.5x. Obviously, the proved reserves per barrel, per flowing barrel, et cetera, are all exceptionally strong, and we'll compare those to Anadarko's 2017 consensus numbers in a couple of slides.

One of the cool things about it is its massive amount of free cash flow coming off these assets over the course of the next 5 years, about $3 billion in the aggregate. And so one of the big issues for us is how can we utilize that cash flow and how can we put it to use to drive future growth, and we'll show you, but the story is that we will reinvest it, in particular, in 2 U.S. onshore assets, the DJ and the Delaware, where we have lots and lots of running room.

The acquisition itself is centered around 7 platforms. Two of those, we operate, and the primary one of which is Lucius. Really, Lucius is the linchpin of this transaction. It represents well more than half of the aggregate value of the acquired property, the E&P properties. We have an asset in Lucius, we'll talk about it in a minute, that we are very excited about, and the opportunity to more than double our ownership position here. So on a pro forma basis, we would own about 49%. Really, was the thing that got our attention and caused us to want to take a deeper dive on the assets that we're less familiar with, those assets are 3 operated platforms that are 100% owned by Freeport. And there are 2 other platforms, Hoover here to the West and Ram Powell to the Northeast where we ascribed very little value. Those are not operated positions that are subject to pref rights. And so the pro forma, the other 5 assets, obviously, the 100% owned and then Lucius and Heidelberg are not subject to pref rights. And so from a structural standpoint, obviously, those were characteristics that were really attractive to us.

At Lucius, I mentioned that we find it exceptionally attractive. One of the reasons is it's really, really big and it's getting bigger. We announced yesterday or when we put out the press release late Monday, we announced that we're taking the EUR at Lucius from 300 million barrels to 400-plus million barrels. That's due to the characteristics you see here to the top right. Really good porosity and permeability. And up to a 60% recovery factor in several sands. So as we continue to take our learnings from the existing production at Lucius and the existing performance of the platform and reforecast going forward, we get more and more excited about what Lucius could mean.

We put a chart on here at the bottom left to show you average daily production rates across the next several years. And you can see that obviously, it would peak in the relatively near future and then we show the decline start to kick in. What this doesn't show is the numerous tieback opportunities in the area. A couple of which are Phobos and Hannibal that we show you on the map where we picked up additional interest in both of those prospects through the acquisition as well, and some acreage in the area that we picked up. We're showing this on a pro forma basis. But if you look at our historic maps of Lucius, you'll see that we picked up some additional blocks that are contiguous and help us to control the leasehold position around several of the prospects in the area. So if we -- if you think in terms of kind of a max production rate or a -- which is certainly well in excess of nameplate capacity recently where we recently clipped 100,000 barrels per day, if you think in terms of extending that level of production out well into the future and filling up that wedge where we're currently showing declines, it's a big part of the story here. We're able to keep Lucius high, production rates high with a lot more tieback opportunities. And really, we think we're able to extend this type of an approach, not just in the things we've talked about historically in our tieback inventory in the Gulf of Mexico, but we picked up numerous tieback opportunities, around 20 or so, associated with the other platforms that we're acquiring and we'll control prospectively. So it's a continuation of our strategy in the Gulf of Mexico and the things we've done exceptionally well for a number of years.

I mentioned a minute ago, a lot of free cash flow this kicks off. What do we do with it? And that's really one of the things that got us excited as we delve into the deepwater portfolio of Freeport more significantly was when we start to understand that cash flow profile. We spent a lot of time modeling and reoptimizing our existing portfolio when we add that cash flow in this production profile from the acquired assets to our base case model. And what we found was that it really served to allow us to grow within cash flow at a much faster pace. Some folks have asked us about this, that we had talked about going back to work and adding rigs if we get to $55, $60. Really, the governor on that wasn't so much the economics of what we're investing in because the economics in the DJ and the Delaware and our positions there is absolutely phenomenal. But what was the governing factor was the cash flow. And absent $55 to $60 oil, historically, we didn't generate enough free cash flow to be able to really drive growth inside of cash flow without either putting pressure on our need to issue equity or putting pressure on the balance sheet or additional asset sales. But when we add this significant free cash flow now, incremental free cash flow coming out of the Gulf of Mexico, it gives us enough free cash flow that we have the ability to, within cash flow, accelerate our drilling activity in the Delaware and the DJ. And in fact, we intend to do that starting, really, immediately, even though the transaction won't close till later this year, by adding 2 rigs in the DJ and 2 in the Delaware. You see at a bottom right what that does for us from a consolidated standpoint. It takes our current production from a little under 300,000 barrels a -- 300 million -- 300,000 barrels a day to a little north of 600,000 barrels a day. So think of it in terms of it doubling. So we're doubling our position in the Gulf of Mexico. It kicks off free cash flow to allow us to double our production from the combined resources in the DJ and the Delaware. And hopefully, when you see that, you can understand why we got really excited about this, and we're able to do it with a significantly accretive equity issuance.

We've put some statistics on here for the Delaware and the DJ. Most of you are familiar with our story. We summarized them here. The key here is we have tons of running room, great economics and really, the whole issue here was, how does it fit within our cash flow profile and our spending profile going forward. A little more detail on the Delaware. We've got over 550,000 acres from a gross standpoint. It is a broad position, about 50 miles from the Northwest to the Southeast. We believe it's in the core of the core. We think we've got one of the best large positions in the core of the core in the Delaware. Lots of productive zones, as you can see in the chart to the right, numerous wells per section. We have lots and lots of running room. And importantly, we have the infrastructure in place and the game plan around expanding that infrastructure from a gathering and processing and water handling standpoint through our MLP to be able to execute on this plan and to control the timing of our own development. We have yet to move to pad drilling approach in the basin. We will do so in good time. But our intention today is to accelerate what we're doing. And in doing so, we bring forward -- by accelerating our program here and in the DJ, we bring forward in our estimation, north of $1 billion of value on a PV basis solely by accelerating the development plans here versus our prior base case.

So we show you on the following slide our oil growth profile. We're talking about a profile that is big to begin with, and it just gets bigger. We showed you kind of some company-wide -- or some basin-wide numbers on the DJ and the Delaware earlier. This is company-wide oil growth, driven by oil growth in those areas and adding to it the oil growth from the Gulf of Mexico base case as well as the acquired properties. And obviously, the numbers here, I think, are quite impressive for a company our size. And as you see, we've really just used one variable here, and that's price. And the reason is, again, that it has to do with how much cash flow we're going to be able to generate from our entire portfolio and therefore, how much cash flow we have available to reinvest. With a little more cash flow here, we've modeled that in just an additional $10 per barrel, it gives us the ability to grow on a compounded annual basis over 5 years by an additional 2%.

So certainly, you guys that have followed us have realized we haven't put forward-looking numbers -- material forward-looking numbers out there since I think 2014, roughly, John? The confidence that we have to do it today is something that shouldn't be lost on you. We wouldn't come forward with the types of things that we're talking about. It's not a lot of detail behind them, and there will be more detail on how we get there in our Investor Conference early next year and after we get past closing later this year on the acquisition. But we've been kind of sitting on go waiting to move forward, seeing hopefully an improving demand forecast, although some of the recent data calls that into question. But improving demand and, as Al has talked about publicly, we think we see a $60 price on the horizon. You don't want to be at a standing start when that arrives and so our feeling is we want to start ramping up towards a higher level of activity when we're at $60. But frankly, in advance of that, if we're a little wrong and $60 doesn't get here soon, we know that we're investing in high rate of return assets that have really good characteristics where we can still invest inside of cash flow and if we get the additional price, then obviously, we can push on the accelerator really as hard as we choose to.

Final slide just to touch on the acquisition metrics. This kind of, I think, brings the math home on why you can equity finance it -- entirely equity finance a transaction and be so pleased with it. The acquisition multiple, obviously, I mentioned, incredibly low. The cash flow profile of the asset is tremendous. This is 80% oil, a high-margin asset, almost twice the cash margin per barrel as we have in the balance for our portfolio. Really, superb assets. We've -- thankfully, from our perspective, we had a seller that had decided to exit the position, to exit this part of the business. Didn't fit with their core model. We're one of the few companies, I think, that was very well-positioned to be able to integrate these assets seamlessly and move forward. I think it made us an attractive buyer. Obviously, we were in a good position with a motivated seller. I can't express how excited we are about the future in the Gulf of Mexico for us and what we can do with these assets domestically.

With that, I think I'll leave this slide up so you can keep staring at it while we do Q&A, because I actually stare at it every night now before I go to bed, it makes me so happy.
John and Robin are here. Those of you, I think, saw the announcement recently that John has decided that early next year, he'll be retiring. And so Robin has been promoted to our Vice President of Investor Relations, will take over running the group from John, concurrent with our third quarter call at the beginning of November. And then thankfully, John will be with us through early next year for somewhat of an extended transition and maybe a farewell tour or 2. So with that, I'll be quiet and we'll start taking your questions.

Question and Answer

William A. Anthony Featherston
UBS Investment Bank, Research Division

Bob, maybe I'll start off with a quick one. In terms of the ramp in the Delaware and the DJ, you gave us some numbers. So I think the Delaware goes from 40,000 a day in the second quarter to 130,000 a day in 2021. And that sort of implies that DJ would double from 240,000 to 480,000. Can you give us a handle on how many rigs have to be added over time or how many wells have to be drilled?

John M. Colglazier
Investor Relations Professional

Bill, this is John. I'll actually push back a little bit on that one. I think your starting point is a little off. That is oil only. In 2016, on average, roughly 24,000, 25,000 barrels a day of oil. So we're drilling the oil production from 25,000 up to the 130,000-plus over that 5-year time period. And quite frankly, I don't really want to talk about rig count per se because what we have forecast to get to that level is no incremental drilling efficiencies. So with that concept in mind, you're really kind of focused on well count to get that level. And this is where we -- I think it was I mentioned yesterday in the call, but we would anticipate drilling around, as over time, but going to that '20, '21 time period, we would anticipate about 600 wells a year being drilled in both the DJ and the Delaware Basin. So this is a pretty significant ramp from the roughly 200 wells that we're going to be drilling this year between the 2 basins.

Unknown Analyst

Bob, a quick question over here. In terms of balance sheet, it's obviously in very good shape now. But you guys have been clear that you're working on other noncore divestitures, gas, Marcellus, whatever, Eagle Ford. Obviously, there's not a need for those proceeds. But if you have a large transaction where you get even more cash, can you talk about the use of that cash, whether it be more acceleration, M&A, return cash to shareholders?

Robert G. Gwin
President

Sure. I think the key is we have -- with the transaction and the cash flow transaction that would kickoff, we've got a lot more optionality around what we sell -- and choices around what we sell and whether we sell. And I think it's fair to say that we're not a price taker. We'll get to make our decisions based upon what the market will bear for the assets that are out there. I have gotten asked questions, does this imply that our asset monetization program isn't on schedule or something? And the answer is clearly that this doesn't imply that at all. Our earlier statements around being able to reach the high end of our target range or more of $3.5 billion this year, that remains true. I think we've been real clear that the U.S. onshore story is driven by the DJ and the Delaware. And the DJ and the Delaware tend to crowd out the other assets in our portfolio. Those assets have good inherent economics, even some of the dry gas assets. And the reason we've been successful in selling some is the economics are really solid for other people's portfolio, but they don't compete well for capital in ours. And so we're faced with a situation of do we keep assets that generally are not going to get capital within our portfolio and hold on to them. And maybe they get a little capital down the road when cash flow is so substantial that you'd turn to the assets beyond the DJ and the Delaware for investment, or we go ahead and sell them today and bring cash in and have the optionality around all the things you just mentioned that we might be able to do with the cash. And so that's kind of the decision framework when we're looking at incremental asset sales that we're facing. So what do we do with it if we do sell them? Well, I think it starts with holding the cash and having a look at the market. Obviously, we'll continue to look at what the M&A opportunities are out there. I've mentioned before that we don't like to chase deals that we think are going to be difficult to make good, solid full cycle returns or to see a clear path to how you make money. There aren't any more of these kinds of valued transactions out there, obviously. This was situationally specific. But we'll also be competitive. And in the places where we operate and where we're good and we have competitive

advantages and core skills at -- we'll be aggressive if we need to be if we think it makes us a better company. It's not that we're building up cash in order to be aggressive in that regard. We certainly could do some liability management work with some of that cash. And a lot of it has to do with what the pro forma commodity price environment looks like. Obviously, we are still, I think, good stewards of capital and will not make bold moves just because you have cash, but it gives us flexibility to be able to reallocate capital more efficiently. And if, in many cases, the best acquisitions we can make is to accelerate -- or the best path forward is not to make an acquisition but to accelerate our activity beyond what our internally generated cash flow can do. We've done that historically in assets when commodity prices are low, and then we've generated excess cash and returned it to shareholders in the past when prices are stronger. And I think commodity price environment and the outlook will inform what we do with the asset sale proceeds. But I think it's full speed ahead on our asset monetization program. And I think we have made it clear that there are -- what people have taken to calling the 3Ds, the Delaware, the DJ and the deepwater. But we've got ample opportunities to go put that cash to work and drive shareholder value over the long term.

Unknown Analyst

I have a specific question on your offshore CapEx. I think offshore is about 1/4 of total production at this point, roughly, pro forma for this deal. Can you just talk about what the capital program looks like for kind of '17, '18 if I look at offshore as a business or if you want to separate the Freeport assets, that's fine.

Robert G. Gwin
President

That's probably a little early to talk about it specifically from a percentage standpoint. I think it's fair to say that there is a capital spending plan around the acquired assets that we're evaluating and we'll decide if it's -- if it needs to be optimized either up or down relative to our consolidated portfolio. We have gotten past most of the spending in the Gulf of Mexico beyond tiebacks that we've talked about, beyond adding additional tiebacks in 2017. We've gotten past the significant spending on our other assets. But there's a nice upward -- up and to the right profile around production and cash flow associated with the acquired assets, and so I think it's a question of just how much capital we want to put into those and how does it fit into our reoptimized corporate model. The numbers we've put forward have, of course, been kind of battle tested a little bit within that corporate model, but we're not in a position where we want to talk about how we're going to spend the capital yet.

Unknown Analyst

Let me ask the question differently. The $3 billion of cash you talked about from the acquired assets, is that after CapEx or pre-CapEx?

Robert G. Gwin
President

That's after.

Unknown Analyst

After. And did you give us the CapEx assumption there? I guess --

Robert G. Gwin
President

No, we didn't. But I think it's fair to say that, that CapEx profile is higher in '17 than it is in '18 and than it is in '19. And so the CapEx associated with those assets, and we're talking about tiebacks and additional development work that's being done -- that will be done on those assets, the CapEx starts to fall. And of course, as you spend capital in the Gulf of Mexico, you add capabilities and production profiles that give you an increasing cash flow stream for a while before the decline starts to set in. So the free cash flow impact of that, net of that CapEx that will be -- CapEx will be declining, production will be increasing, according to the free cash flow profile, gets very powerful through, say, '19 before the decline starts to kick in. And then the real question becomes do those declines kick in or do you continue to drill

aggressively on tieback inventory to keep your production profile flat or growing at your facilities. We've got ample capacity, unused capacity, at the -- and Darrell Hollek said this on the call yesterday. Ample capacity at the to-be-acquired assets to be able to be -- to really pick a spending level and a tieback execution profile because we got the infrastructure in place to be able to take those additional volumes. At Lucius, for instance, you saw the chart, we're essentially full. And so we've -- and Heidelberg has capacity. We overbuilt it for the relative size of that field and now we've got capacity through tiebacks in that area. Some of the slides in our existing slide deck actually show you guys that on our existing assets. And I think over time, we'll be able to provide you one on the acquired assets as well. And you'll see that we have optionality then around about 6 different facilities, we'll have optionality around how to time the CapEx and the tieback work to maximize the production profile from that owned infrastructure. Great thing about it is that the brownfield economics in the Gulf of Mexico are phenomenal. And so the real competitive advantage that removes the commodity price environment from the decision-making process. The real advantages is the infrastructure and capacity of that infrastructure. And so a lot of people focus on, well, when are we going to see greenfield development and at what price, et cetera, and we still got a great opportunity at the Shenandoah we're excited about. And so we ask ourselves those questions all the time, right? We're working at answering it. But you don't need material commodity price improvement to make money in the Gulf of Mexico. We're doing it at strip and we think we can continue to do it at strip for a long time to come.

Unknown Analyst

Got you. And then one last final one. I mean, congrats on the deal. The price is really, really good from your perspective. Obviously, it helped you had a semi-distressed seller on the other side. How competitive was this deal? I'm just curious of the appetite for those kind of assets in general, like who else kind of showed up for this thing?

Robert G. Gwin
President

We really don't know. I mean, I think Freeport or JPMorgan advise would have to answer it. I can tell you that we've -- we made it clear to them what we thought our price would be and they were running -- Al mentioned this on the call yesterday. We know there is an S-1 process to take oil and gas business public or subsequently, asset sale processes. We made it clear that we're only interested in the deepwater assets and roughly what we thought our bid would be. Given that we had a lot of insight into Lucius, it was pretty educated bid and they knew it. I think we're also an operator that culturally, we're similar to the work that's been done at Freeport historically, and I think they felt good about us as a buyer and as a financially responsible buyer in the Gulf of Mexico. Who you sell your assets to is something that's a consideration because of asset retirement obligations in the environment where they can come back to you in a chain of title. So I think we were arguably a buyer of choice for them, but we had a price on the table that eventually we received a phone call and started working more aggressively on negotiating a purchase price. So I don't know how deep or what the supply and demand was behind the scenes. I just know that, well, we expressed our interest to the given level and were able to achieve it.

William A. Anthony Featherston
UBS Investment Bank, Research Division

Marcie [ph]?

Unknown Analyst

A quick question following on from Christian. How much did Plains -- I think Plains bought these assets off BP, and then obviously, there was a whole bunch of investment. How much should you know the cumulative dollar amounts of that investment and that purchase?

Robert G. Gwin
President

Of what they bought them for?

Unknown Analyst

Yes.

Robert G. Gwin
President

I don't know what the exact cumulative is. I mean, I've heard a lot of numbers but you guys could decompose it. There were -- it was, from BP, they bought some assets from us that there were -- I don't know. But in fairness to them, they bought them in different environments looking to build a business against a curve -- a price curve that didn't materialize.

Unknown Analyst

Yes. And then going forward, because you have so many opportunities, does this now change the way you view exploration? Because I suppose you have a finite dollar amount you want to spend offshore, whether it be Colombia or in the Gulf, your opportunity set in the Gulf of Mexico is now so low risk. Does that then change your, obviously, need to do exploration going forward over the next couple of years?

Robert G. Gwin
President

I don't think it does. Let me put that into context. We're spending about $500 million in exploration in total this year. Most of that's in the deepwater Gulf of Mexico and internationally. I -- just at a broad level, a macro level, I expect we'll continue at that level at least. It has to be relative to the overall size of your opportunity set, to your point, and your future. But it's an area we've made lots and lots of money, and we've got a great slide that many of you may have seen in the deck. What we've done in the last 10 years, the exploration has been a profit center. We've spent billions of dollars. I won't go into all the math, but billions of dollars, about $10 billion over that time, made a cash profit. Also have been left with a tremendous amount of resources that we're taking development and a number of additional things that we will move forward towards drilling in the future. And if you step back and think about exploration as a core competency and a core skill set, you want to continue to invest in it, and you want to invest in it beyond just your opportunity set that you're facing today. And the reason is when you have that additional optionality, we were able to do things like finance the development capital at Lucius and finance the development capital at Heidelberg and de-risk assets across the portfolio, sell a big chunk of Mozambique. Do the types of things we did that added tremendous financial leverage to our model without adding -- without any balance sheet leverage to the model, utilizing other people's money because we had confidence that our exploration profile had been able to provide us with, that we had confidence from what our future growth looks like. And so if you take that same concept and roll forward, that hasn't changed. So we're going to continue to spend money on exploration. The key is where do we spend it and how do we spend it. We have a bigger footprint in the Gulf of Mexico but we also have now more exploration inventory. I mentioned seismic earlier. That gives us options. We also have 3 facilities where we have 100% working interest, prospectively. And that's a higher working interest than we have traditionally owned in any of our assets in the deepwater. So I think it's fair to say that we look at this as additional option value in our portfolio to be able to cut better deals going forward and to pick and choose. What we generally say, it's in one of our slides, you develop the best and sell the rest or something like that. I mean, it's a little oversimplified, but it gives us the option to be able to pick and choose how much capital we want to spend, where we want to develop it, pick a growth profile and then be able to leverage our success in our deepwater exploration program through bringing in partners and helping our own economics.

Unknown Analyst

Yes, just a couple more. And if I heard you correctly, it was out until 2019 that you would be able to keep production flat. Now that's excluding the tiebacks or including?

Robert G. Gwin
President

No, I wasn't talking about our -- anything relative to our production profile. What I was talking about is that on the acquired assets, when we look at that incremental free cash flow from these assets, $3 billion at strip, $4 billion at $60 oil. That's driven by production and cash flow there is increasing and CapEx, that's falling. It wasn't coming on production itself.

Unknown Analyst

Okay. And the 20 tieback opportunities, is that x incremental drilling in Lucius? Or does that include...

John M. Colglazier
Investor Relations Professional

The 20 tiebacks that we're referencing in the acquired properties is all from the 3 100% owned facility stand-alone. And they have a different profile. They're a little different than those big 20-plus million barrel opportunities we have at Lucius, Caesar/Tonga and K2 that we've been mentioning previously.

Robert G. Gwin
President

What they don't include that I think is interesting, and we'll have more detail on this probably not until next spring, but we've been successful with our infrastructure when there are other folks that own properties where we're not a partner. If they have some stranded discoveries that are sized properly for our facilities, we actually give them production solutions and cash flow solutions that sure beat them having to walk away from their discoveries. And that gives us some very interesting leverage in negotiations, helps us to back-end the working interest positions or operatorship positions. And of course, there is kind of a merchant business. And Freeport had just recently signed a production handling agreement with a third party at their Marlin facility and -- which is essentially saying we've got the infrastructure and we'll simply take production handling fees, and they recently signed that. Actually, we're going to inherit that and give them some of the economics associated with it as some contingent upside for them if that comes to pass. And that type of thing, that kind of leverage, when you have the infrastructure and you're the best solution in the neighborhood, it gives you an asset that you can best use to maximize your value.

John M. Colglazier
Investor Relations Professional

I think the other way to look at that, too, Rod, from incremental value going forward is that the $1.7 billion property allocation that we have mentioned in the acquisition, that is only for the proved reserves and the low-risk development tiebacks across the acquired assets. And so it doesn't include the upside from the 3P aspect nor from the 15-plus exploration opportunities we've identified in it. We don't have the capital in there either, but it doesn't include that upside and opportunity you get from those opportunities.

Unknown Analyst

I had another question. You talked about having room in those facilities offshore. Can you talk about what their present utilization is? How much room you have to run there? And with the current production absorbing all the fixed cost, how much can you lower the fixed -- the cost per barrel to operate these as you get more volumes across there?

Robert G. Gwin
President

Good questions, but we're not in a position to go ahead and answer them yet -- talk about them yet. We want to get the acquisition closed and then we're going to start talking about revealing a lot more of the plans around them. I think your observations though are accurate that -- and it's one of the reasons that the economics of the tiebacks are so attractive is that you essentially have a fixed cost and the capital program that's behind you. You have fixed operating costs and the capital program is behind you, and the marginal economics associated with tiebacks therefore have tremendous financial leverage.

Unknown Analyst

Since those have such great financial leverage, do you think that, that gives you the opportunity -- and I know you've talked about not changing the plans yet. But it sounds like economics, to make use that operating leverage, means that you might do more drilling in the Gulf of Mexico to take advantage that those economics offer?

Robert G. Gwin
President

Well, I think the answer to that is absolutely yes. But the drilling is we're talking about tiebacks drilling. We're not -- and we continue an active exploration program. We -- we're going to spud Phobos here as we've talked about on the map, for instance. So we are going to continue to drill. I think that given where -- you want to drill -- generally, it's lower risk in this kind of environment to drill closer to infrastructure though. So when we're drilling, we generally are already thinking a production solution as opposed to in an environment where we have materially higher prices. You know that the production solution is economic with success anyway. And I think that in the current environment, you're simply trying to make good risk-adjusted decisions. That means generally drilling closer to infrastructure and then understanding -- you don't want to feel -- you don't want the success to look like it's a commercial failure because it's too small for its own infrastructure because you drilled in the wrong location. So you've got to spend your dollars more likely than that.

Unknown Analyst

Do you think that given where rig rates today and you can get some so cheap, that would really improve the economics now that you have these opportunities on your plate and the infrastructure. So is that a potential to pick up more rigs and go ahead and do that?

Robert G. Gwin
President

I don't think I jumped to that yet. But certainly, the environment is very conducive to being able to do so. But again, it's how it fits within the overall portfolio. We've got some rigs that are rolling off in '17, '18, et cetera. We've got some rigs and we'll obviously want to reoptimize where we're going to utilize the rig fleet in the Gulf of Mexico given that we'll have new prospects and leads and infrastructure. But yes, the marginal value in the Gulf of Mexico is really strong right now when you're talking about picking up rigs at the kind of rates that are available. But that's a TBD for 2017 after we close and as we put the 2017 plan together. And I think it will be something we'll be in a better position to address more specifically when we do our rollout in early March next year.

Unknown Analyst

And this is kind of a silly question. What does it do to your split between gas and oil production with the additional oil production, overall as a company?

Robert G. Gwin
President

I don't if we've got a pro forma number we've announced.

John M. Colglazier
Investor Relations Professional

Yes, I'll talk about it. With the -- being 80-plus percent oil, what we're bringing in, the Lucius outperformance. I think consensus for next year is about a 42% oil content and the aggregate, bringing these volumes in will push it up to 46%. So you have a full 10 percentage point increase in your oil competition -- composition.

Robert G. Gwin
President

Then liquids on top of that of another, what, John?

John M. Colglazier
Investor Relations Professional

Another 100,000-plus barrels of liquids on top of that.

Robert G. Gwin
President

Yes. I think it's fair to say that as you drive through some of the -- as we -- and we'll be communicating it more fully, but if you drive through some of the math beyond next year, I think we're kind of pointed more toward of a pro forma 70% number if you just look at where all the growth is coming from, it's all coming in oil. We're divesting gas assets, and the combination those things continues to move us into a 70% oil and liquids environment. And a lot of the remaining gas is obviously associated gas in the DJ and the Delaware, which actually -- I mean, the great thing is that, and I think Al mentioned this the other day, but the associated gas gives us a lot of good leverage to improving gas prices. It's still a -- we're still a very, very, very large gas producer, and will benefit from increasing gas prices. But we like the in inherent economics and margins associated with oil, obviously. A lot better for several years to come.

Unknown Analyst

Just specifically for the Gulf of Mexico, though, can you provide some context around kind of the step-change though in the oil mix there? I think last quarter, it was about 3/4 of the base was oil, you're buying production at 80% oil and you're guiding to the ones 55% to 85%?

John M. Colglazier
Investor Relations Professional

Yes. That one's pretty easy, Marcus. Look at what Lucius has done versus the second quarter to where it is now, eclipsing 100,000 barrels a day of oil. That movement alone is what's driving it, and that will get better when we bring the other Heidelberg well on later this quarter and another one following that in December.

Unknown Analyst

Bob, just a couple of clarifications. You mentioned that the pref rights on the 2 non-operated platforms. Could you just outline the timetable as to when those pref rights have to be exercised, if you know?

Robert G. Gwin
President

No, I can't. Actually, you stumped me, because I've forgotten the time line on them. But obviously, we're talking about closing sometime late this year, and we'll have some insight into those, we would expect, sometime in the next couple of months.

Unknown Analyst

Okay. And obviously, you bought now and we've talked earlier about disposals. Would this transaction allow you to do a like kind exchange in terms of a tax efficient structure?

Robert G. Gwin
President

I think it's conceivable. But I think -- I don't want to make any definitive declarative statements, it's conceivable. And certainly, one of the things that our folks are always looking at is how we best do things tax-efficiently.

Unknown Analyst

Shifting to the Permian, can you guys talk just a bit about -- so several parts to this question. Can you talk a bit about the uplift in drilling efficiency that will happen from the rigs that you have operating now to when you shift into development mode late in '17, and then also talk a bit about completion, lateral length

optimization others aren't targeting? I guess, just kind of give us a broad sense for how the Permian could improve going into next year and '18?

Robert G. Gwin
President

Sure, Robin.

Robin H. Fielder
Senior Vice President of Midstream

I think Bob mentioned that earlier that we haven't -- we have yet to go pad mode. So we're still drilling out there, delineating that stack, understanding how many different zones are going to be productive for us, what they look like. And it's really about performing that fully integrated development plan, as you mentioned. So that includes the completion design, the well spacing themselves, the targeting and then also how that's going to all fit in with your surface, because we're -- obviously with utilizing our MLP in West, we're putting in all the infrastructure. So you want to go out there and make sure you've got a good plan when you go put out your pad, lay your pipe and get everything done once, you're not having to come back to locations. So that's ongoing right now. And I think Darrell mentioned on the call yesterday that probably sometime this time next year, by the end of next year, is we're looking to go into that development mode, and that's when you really see the efficiencies, when you can do pad and batch drilling, batch completions and operations and get ourselves set up to see the improvement and efficiencies that we've gained in the DJ. So taking a lot of those lessons learned and then transferring them down into West Texas. Keeping in mind that we are a little bit deeper here, it's hotter, so the well costs aren't going to exactly 1:1. But remember in the DJ, we're drilling wells averaging less than a week there. So you can imagine we're looking at some of those efficiencies. But on the well counts, we are talking about going up to 500 to 600 wells a year because just massive opportunities we've got there. The 7,000 wells in the Wolfcamp A we mentioned. Remember, that's just the Wolfcamp A. So as we delineate these other zones, there's a huge opportunity in front of us and we want to make sure we bring forward that value. So you need to be running at a pretty fast rate to make sure you're taking care of those resources appropriately.

Unknown Analyst

Well, I guess can you just talk a bit more about just the well productivity once you do have the water, the crude infrastructure in place where you're not choking back or managing the wells as much as you are now. And I guess, if there are also an uptick in completions, are you already at an optimal completion right now or does that change in the next 6 months?

Robin H. Fielder
Senior Vice President of Midstream

As far as an optimal completion?

Unknown Analyst

Yes. From what you are -- from what you're doing now for the typical well at least --

Robin H. Fielder
Senior Vice President of Midstream

I guarantee it will change. I mean, we're going to right size it. We've got -- I mean, Bob mentioned the massive footprint we've got out there talking to a 50x50. If you look at the outline we've got for our core section in the DJ, that little state of Idaho, you can fit 3 of those within our Permian Basin position there in the Delaware. So it's huge. We've got to make sure we understand how the fluid compositions change across our acreage. So -- and then you've got to think about it in 3D. So that's for 1 zone, and then you've got multiple zones there. So I guarantee we'll be changing that and tweaking it and you want to optimize that not just based on the fluid properties, but it comes down to a function of maximizing present value. So you've got to take it into your commodity pricing as well.

John M. Colglazier
Investor Relations Professional

Yes. And John, let me add onto that. I think when Bob mentioned that we think we're in the core of the core out here, I think we can talk about that all day, but I think industry's already validated that. But when you take the combination of 1 of the 3 key drivers, the overpressured section, you draw the bubble map around the acreage out there, you couple that with the area with the best porosity and then you look at the total TOC map, it overlays perfectly across our acreage position. So there's no doubt that we have an incredible opportunity ahead of us. And I think you're hitting us where we're learning and trying to maximize and improve upon each of those stages, whether it's laying in the waterlines, whether it's sizing the facilities out there. We're doing that all now. So this is evolving, we're learning, we're getting better as we go. So I think I'd rather show you, and that's what we're trying to get to when we say that we're moving to that -- about this time next year, start moving to the pad drilling to really showcase what our Delaware Basin position is capable of. So all great questions but I think we're getting there as we go through here.

Unknown Analyst

Additional Delaware questions. Obviously, you guys are checkerboard-ed with a major on a lot of that acreage. Are they participating in all your wells? Is there an opportunity to either split 100% working interest in either or add and fill in?

Robert G. Gwin
President

I think I'll declined to get into the specifics. But I think it's fair to say that we are working, I think, well. Our team's working well with their team to continue to advance the program. It doesn't necessarily mean that we all see everything the same way. And so in certain circumstances, we may or not participate something they do, they may or may not participate something we do. But I think for the most part, we both realize we're sitting on some absolutely superb acreage and working together to try to define what that means in terms of the most efficient path forward. And I think I'd say the quality of the relationship, the quality of the dialogue is very, very good, and that endures to their benefit and ours.

Unknown Analyst

Bob, had a question on the DJ and the Delaware. The growth rates that you gave us, how much of that growth is governed by the cash flow available to reinvest in a $50 to $60 world versus the midstream infrastructure. And if oil prices were to go higher, is the midstream in place to accelerate growth even further?

Robert G. Gwin
President

It's a great question. I mean, the midstream's in place to execute what we are currently working on in our -- and the rigs we're adding and West continues to add processing capacity, additional trains at Ramsey. So it is -- the infrastructure, I think, is -- it's fair to say, is the plan on the infrastructure is to get it just out in front of the upstream. And especially within an MLP structure, you don't want to get the capital out in front of the cash flow very significantly. It is -- the great thing is it is in place to cash flow for us to start cash flowing from our upstream drilling activity today. And we -- because we control the pace of the development of the midstream, we're not reliant upon anybody else's capital budget or customer base or anything other than our own to be able to make sure that those 2 things stay in sync. We put -- it's -- our position there, West and Anadarko combined midstream, we think our position is quite a large midstream consolidated position in the Delaware, and I expect it's going to continue to get bigger. We've got a lot of third-party customers out there. West -- and West's material show that. That endures to our benefit because obviously, we have less risk when we build. We can build a little bit larger and we've got the ability to bring other people -- other customers to the table. And West has built, I think, a very good reputation as an operator for those third-party customers. And so I think it's all built -- I think it's kind of -- it's all synced up and working very well. And we see it as a real significant competitive lever. And obviously, the economic benefit back to Anadarko through our material equity ownership of the general

partner and incentive distribution rights associated with it gives us -- if we start to take the economics we've got and we lump in full cycle economics, including our ownership of the MLPs, the math is just really off the charts.

Unknown Analyst

Had a question on the tiebacks. I think you said Phobos and Hannibal are 100% working interests. And I know -- I'm not sure if that pertains -- if this pertains to tiebacks or greenfields investments. But typically, you've developed stuffs in the Gulf of Mexico with a 30% to 50% working interest. Obviously, tiebacks are a lower risk. How do you envision developing those tiebacks?

Robert G. Gwin
President

I think it's -- I'll leverage -- this comment, I'll leverage off something I said earlier. I think it is that we have optionality around things we own 100% in. There are players in the deepwater that -- and it's the way we're able to develop with our Japanese -- separate Japanese partners at each of Lucius and Heidelberg. There are folks that want to participate in wildcat exploration all the way through folks that want to buy very low risk development. And so each stage to the process offers its own economics for us to reduce our working interest. And obviously, the more you de-risk it, the better your economics are. And so we just have a portfolio approach on it, where some places, we tend to farm down prior to drilling the first well. In other places, we wait until we're into development mode and then get the best leverage to our marginal dollar. So the answer is, it's not specific to any particular asset. It's more from a portfolio standpoint, we look for the transactions that give us the best economic benefit and cause us to have the best consolidated performance risk return trade-off across the portfolio. I hope that makes sense because it's not real linear in terms of how we look at it. It's kind of asset by asset. Yes?

Unknown Analyst

In the Permian, you mentioned that you're in the core of the core. How long do you see that inventory being in the core of the core? Is that a 2-year, 3-year horizon before you start to move to that second ring of the core?

Robert G. Gwin
President

I think it's a lot longer because I don't think you move out from the core of the core. You're moving up and down within the stack pay and Robin mentioned, we were just looking at numbers, we've put up there 7,000 opportunities. She talked about a number of wells per year. That's many, many years just in the Wolfcamp A and of course, the number of additional wells per section as we learn more. And as the economics and the -- continue to improve. Keep in mind, once you've got infrastructure in place, it's a hell of a lot cheaper to be able to go vertically up and down within your existing acreage rather than to start to step out and build additional infrastructure. So there's a whole lot of what we think is leverage upside as we take it the next step beyond that initial opportunity set that we've put on the slide.

John M. Colglazier
Investor Relations Professional

Yes, I think the other way to look at that, we have 900 sections out here, mile by mile. And we know that we're going to put at least 8 wells per section out there. That's the 7,000 wells we talk about. Now you go up and down the stack, you can have some massive well count opportunities out here. And that's what we're working on now, is figuring out how do we attack that. We've just taken a step here. We're talking 600 wells. Well, that's a massive inventory life. So how do you work for ways to further accelerate that, et cetera.

Robert G. Gwin
President

Well, that key here is to make money, right? That's why we're all here. And I think it's important then to consider your entry cost. And we have very, very low entry cost in our position because this was a --

primarily, this acreage is associated with the legacy Haley gas field that we had here for years. Because the entry costs are so low, when we're talking about all the stack -- because all the stack payers is additional economic value. It's leveraging the existing investment. So the acreage prices that are out there, everybody knows, is due to the kind of 3D nature of the acreage. And I think people are looking to try to determine where does that acreage price settle in and what's too much when we start seeing people paying $50,000 an acre or something. Well, our challenge is, with acreage prices where they are and entry costs so high, you have to assume some level of development of multiple benches in order to justify the acreage. Everything we're looking at was justified a long time ago because of the very small entry cost. So the Wolfcamp A is huge. The rest of it is all land that costs us nothing to get into. So I think it's important to think about how a company is actually going to make money in the play, and they might get -- they might pay a premium for a beautiful position and they may be able to make a lot of money over time in doing so. But they're paying for upside beyond the initial benches, of course. And so I think that's one of the things that challenges us as we look at acquisition opportunities in the area. It doesn't mean we won't make some because certainly, there are some stuffs that we've got our eye on that we think is very attractive. But it's a question of what's the right price to pay for it and how much of that future development are you owning in your acquisition price. And the risk dynamics around that opportunity are -- different companies, different investors see that in different ways. One of the nice things is because our position already exists, we feel like this is -- the economics of this in going ahead and pushing on the accelerator are self-evident.

Unknown Analyst

And then as a follow-up, if you don't mind. And -- when you talk through your economics and you go think about 2017 and going into '18, what are you assuming in cost inflation that we'll start to see in the industry and how you think that plays back? Do you think that comes back slowly on the cost inflation? Or is that more meaningful? And do you think we get back to the same cost level that we saw last cycle?

Robert G. Gwin
President

Without mentioning specific numbers, and we do -- we've modeled this a bunch several ways we've done and the you -- I mean, lots of people have done it. We've used outside sources. We've done our own work trying to look at correlations of how costs have behaved historically. There's going to be cost inflation, without a doubt. The industry -- the capacity of the service companies, if everybody decide they want to go back to work at once, it's functionally impossible. We're talking about labor, parts, all the stuff that everyone's familiar with. So what we've tried to do is to take a look at how -- model cost inflation relative to the commodity price environment and get a feel of outcomes around how margins might be affected. And I'll oversimplify, but I think it's fair to say that we would expect some margin expansion up through the prices that we've been talking about in this presentation, our margin expansion. And then my personal belief is almost all of the incremental dollar is going to start to flow to the service companies for the next, I don't know what it is, $10 a barrel, something. I mean, there's going to be some level at which our margin expansion is going to be very, very small compared to the improvement in the commodity price, which is why we look at the net economics to ourselves and say, "Well, we can model this thing into kind of $60 range, but we certainly aren't going to model that you've got $10 of margin enhancement once you get past $60." And it's not like we're saying $60 is a bright line. As you might imagine, we've modeled it lots of different ways. So we expect to capture the additional margin for a little bit, then to capture virtually no additional margin for a while. And then to get back into a situation where the dollar is split, I'll call it, fairly between the service companies and ourselves. And frankly, that kind of a framework is okay with us. We need a healthy service company universe in order to execute our programs. They're partners of ours. They're central to our safety performance and our efficiency gains. In the types of things that we want to do well, we need a good, healthy service sector. And they, like a lot of the industry, has been on a tear for a while and so their ability to get back in the game and make money is going to help us over the long run.

William A. Anthony Featherston
UBS Investment Bank, Research Division

I think Anadarko said they have time for one more question so I'm going to take it. The growth guidance that you gave us through 2020 or 2021, does it envision any rigs or wells for the Eagle Ford or your dry gas plays?

Robert G. Gwin
President

No, not really. Not in those numbers. I mean, we've got some work that we're doing because we've got some uncompleted well inventory and some things where we'll spend capital. But not really from a rig count or enhanced activity level. There's -- it's hard to say specific -- it's not hard, it's just that it's -- we don't want to say specifically no activity because there are certain things we should do to optimize the value the asset, but that's not the kind of thing where you're saying we're going to add 2 rig lines and a completion crew or that kind of an approach. It's -- this doesn't include any of that type of activity increase.

William A. Anthony Featherston
UBS Investment Bank, Research Division

All right. That, I think, we're out of time. So please join me in thanking Anadarko.

Robert G. Gwin
President
Thanks, everybody. I appreciate your time.

Exhibit 115

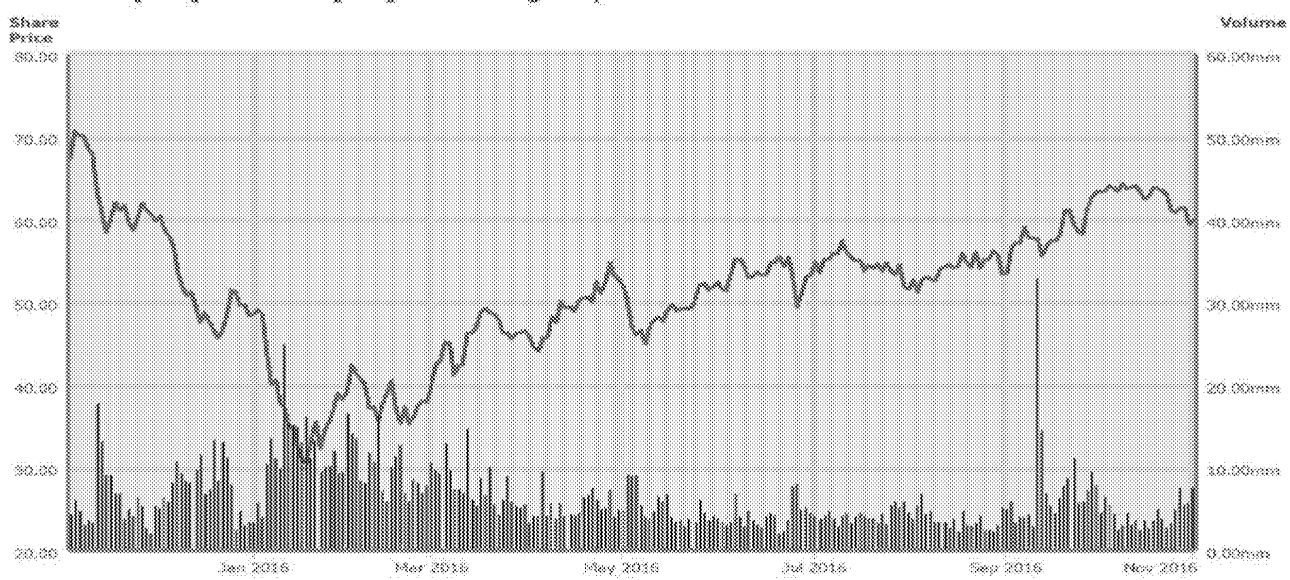
S&P Global
Market Intelligence

Anadarko Petroleum Corporation
NYSE:APC
FQ3 2016 Earnings Call Transcripts
Tuesday, November 01, 2016 1:00 PM GMT
S&P Global Market Intelligence Estimates

	-FQ3 2016-			-FQ4 2016-	-FY 2016-	-FY 2017-
	CONSENSUS	ACTUAL	SURPRISE	CONSENSUS	CONSENSUS	CONSENSUS
EPS Normalized	(0.56)	(0.89)	NM	(0.51)	(2.85)	(0.37)
Revenue (mm)	2176.13	1893.00	▼(13.01 %)	2393.61	7821.00	11630.79

Currency: USD
Consensus as of Nov-01-2016 12:40 PM GMT

Stock Price [USD] vs. Volume [mm] with earnings surprise annotations



	- EPS NORMALIZED -		
	CONSENSUS	ACTUAL	SURPRISE
FQ4 2015	(1.09)	(0.57)	NM
FQ1 2016	(1.18)	(1.12)	NM
FQ2 2016	(0.78)	(0.60)	NM
FQ3 2016	(0.56)	(0.89)	NM

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Call Participants

EXECUTIVES

Darrell E. Hollek
Former Executive Vice President of Operations

Ernest A. Leyendecker
Former Executive Vice President of Exploration

John M. Colglazier
Investor Relations Professional

Mitchell W. Ingram
Executive Vice President of International, Deepwater & Exploration

R. A. Walker
Chairman & CEO

ANALYSTS

Arun Jayaram
JP Morgan Chase & Co, Research Division

Brian Arthur Singer
Goldman Sachs Group Inc., Research Division

Charles Arthur Meade
Johnson Rice & Company, L.L.C., Research Division

David Martin Heikkinen
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Pearce Wheless Hammond
Piper Jaffray Companies, Research Division

Robert Alan Brackett
Sanford C. Bernstein & Co., LLC., Research Division

Ryan M. Todd
Deutsche Bank AG, Research Division

Scott Michael Hanold
RBC Capital Markets, LLC, Research Division

Presentation

Operator

Good morning, and welcome to the Anadarko Petroleum Corporation Third Quarter 2016 Earnings Conference Call. [Operator Instructions] Please also note, today's event is being recorded.

I would now like to turn the conference over to John Colglazier. Please go ahead, sir.

John M. Colglazier
Investor Relations Professional

Oh, thanks, Rocco, and good morning, everyone. We're glad you could join us today for our third quarter conference call. I'd like to remind you that today's presentation includes forward-looking statements and certain non-GAAP financial measures, and a number of factors could cause actual results to differ materially from what we discuss today. So I encourage you to read our full disclosure on forward-looking statements and the GAAP reconciliations located on our website and attached to yesterday's earnings release. In just a moment, I'll turn the call over to Al Walker for some brief opening remarks.

And as most of you know, after 41 quarterly calls, 10 investor conferences or updates, I'm retiring from Anadarko, and today is my last day in Investor Relations. I've had a great time working with the company over the years, and especially working with you guys on -- over the course of my 10 years here in Investor Relations. I'm very confident in passing the baton to Robin Fielder who, along with Pete Zagrzecki; and the newest member of the IR team, Jim Grant, a geoscientist, who is replacing Shandell Szabo, who was recently promoted to Vice President in our onshore group. These folks are more than capable of continuing to provide the level of service that you've come to expect from us.

And with that, I'll turn the call over to Al.

R. A. Walker
Chairman & CEO

Well, thanks, John. It's a bittersweet morning, but we achieved a lot in the first 3 quarters of 2016 and positioned the company well. And we've also positioned the portfolio for the future, with our assets in the Delaware, DJ and the deepwater Gulf of Mexico serving as the primary sources for our growth.

As a result, we're increasing our anticipated divestiture adjusted sales volumes for the year by 8 million BOE from the midpoint of our initial expectations, continuing to make significant reductions in our cost structure, expecting to now close more than $4 billion of monetizations this year and projecting to finish the year with more than $2.5 billion of cash on hand.

Operationally, we've accelerated activity by adding 2 rigs in the Delaware Basin of West Texas. The company's made great strides to enhance the economics of our premier position in this world-class oil play. This has been achieved by further cost reductions while incorporating an enhanced completion design that's increased our EURs to more than 1 million BOE per well, which enjoys a very high oil cut.

With our increased rig activity, we will continue to rapidly evaluate the stack pay potential across our almost 600,000 gross acres in this position. And as we move to start the development program for next year, we're quite excited.

In Colorado, the DJ Basin also added 2 rigs, and that has been done during the quarter. Our organization has done a fantastic job of driving savings and efficiencies here as well, enabling us to deliver more for less. As a result of these savings, we will reinvest this capital and drill 90 more wells, complete 50 additional wells, and with -- combined with our base optimization, we will provide more than 5 million BOE of additional production, well above our expectations.

In the Gulf of Mexico, Lucius continues to outperform, achieving a daily record of over 100,000-plus barrels of oil per day. This, along with new production from our development wells at K2 and Caesar/

Tonga, increased our year-over-year oil volumes in the Gulf of Mexico by 10,000 barrels per day to 65,000 barrels per day.

And as we announced last month, upon closing the acquisition of Freeport McMoRan's Gulf of Mexico assets, we expect to double production in the Gulf of Mexico to about 160,000 BOE per day, 85% of which is comprised of oil. We will plan to use a portion of the $4 billion of cash that we will have at quarter-end to fund our acquisition and redeem the remaining $750 million of senior notes due September of 2017. As noted in last night's news release, we also expect to receive in excess of $1 billion of proceeds from the pending divestiture of our Carthage assets in East Texas.

Our monetization program has significantly exceeded expectations as we streamlined our portfolio and materially strengthened the financial position of our company. We are increasingly more focused and competitive as a result. And as mentioned, our expectations continue accelerating our activities in the Delaware, the DJ, as well as growing the Gulf of Mexico, in an effort to improve the production and the investment of our company. This should result in delivering oil production with a combined compounded annual rate of return over the next 5 years that will show very strong double-digit growth.

Our employees have done an outstanding job of ensuring that we enhance value in the near term, and now, well into the future. I want to thank each of them for the long hours and hard work that have resulted in having Anadarko be very favorably positioned, given the operating environment in the last 2 years.

And before I turn it to Q&A, I also want to express my appreciation from the board, from management and all of the Anadarko employees for the years of tireless effort John has provided to us and to our shareholders. John, you've done a few -- a lot of things that few can, and you'll be greatly missed. These calls won't be quite the same, but we will always remember those things that you did to make everything at Anadarko go so well on mornings when sometimes it just didn't seem to go as easily as it could have. With that, let's open it up for questions.

Question and Answer

Operator

[Operator Instructions] Today's first question comes from Arun Jayaram of JPMorgan.

Arun Jayaram
JP Morgan Chase & Co, Research Division

Al, I wanted to start a little bit in the Delaware. We saw a pretty punchy evaluation for the Silver Hill asset package and Loving and Winkler, with the transaction, I think, fetching more than $40,000 per acre. I was wondering, first, if you could remind us of your acreage position in Loving. And if you could discuss your broader delineation efforts beyond the Wolfcamp A, because clearly, the industry's pretty excited about the stack pay potential in the Delaware.

R. A. Walker
Chairman & CEO

Well, Arun, thank you. I might have Darrell help me a little bit with some of the questions you asked. But let me just say, as we looked at Silver Hill -- and obviously you know the geography quite well. You know they're right next door to us in terms of how their acreage is very close. As I've looked at how these acreage values have increasingly gone to places I would never have imagined. I mean, we're paying -- or seeing people, rather, pay price per acre today that exceeded acreage values when oil was over $100. And so consequently, I think we have a little bit of pause around just the valuations and how certain of these have escalated in places. I think as we've talked to you about more than once [ph], the rock that we have and the Tier 1 acreage position that we're fortunate enough to be able to enjoy have given us a lot to be proud of. Now it's not just the Wolfcamp, as you've heard us talk about on a lot of occasions. It's in addition to the Wolfcamp, the Avalons, the Bone Spring. And as a result, we have a lot here. And so maybe rather than having me explain things in detail, I'll have Darrell do so. But I will just comment lastly, and it relates to just M&A in the Delaware portion. I don't think we're done. I mean, I think I saw something from one of our competitors that said that we might see $100,000 values per acre out here pretty soon. I'm not sure if I can imagine that, but I also can't believe that we're double where we were in 2014 on a per-acre basis either. So Darrell?

Darrell E. Hollek
Former Executive Vice President of Operations

Yes. Let me just start with saying most of the acreage we have we do feel is Tier 1. And when you look at Loving County, and we probably have half our acreage sitting in Loving and we actually think that's the best of the best. So we're very content on what we have. When you think about what else is there outside the Wolfcamp -- and we recognize those things and we keep quoting numbers on the Wolfcamp, and that's because we think that's the largest prize, not that the other ones won't contribute to our bottom line over time. But if you go back to the offshore part, you can see on Page 6 some of the -- because of our acreage position being as large as it is, we're continuing to spend time to make sure we understand the Wolfcamp, particularly the Wolfcamp A. It's the -- it's by far the best zone because it has a number of benches in it. We're not discounting the Avalon and Bone Springs. We think they have a lot of potential. But at this point, we're going to some of the deeper depths and testing that first. So we'll get to that, eventually. But right now, we're really focused on exploiting the Wolfcamp and understanding exactly what we have in our position. And we've been pretty pleased as to what we've found to date.

Arun Jayaram
JP Morgan Chase & Co, Research Division

Great. And just my follow-up, Al, if some of the media reports are true, you may be shopping your Eagle Ford position. You talked about maybe exceeding your divestiture target this year. I guess, my question is what you plan to do with potential proceeds from all of these asset sales that you've either closed or are pending.

R. A. Walker
Chairman & CEO

Well, it's a fair question. As we continue to talk more about the fact that we see the Delaware, the DJ and the deepwater Gulf of Mexico being our growth engines, I think in that cascading order that I just gave you, that's where we would put incremental dollars to work, would be Delaware, DJ, deepwater Gulf of Mexico. Our ability to redeploy some of the capital and cash that I talked about in my prepared remarks, if we additionally have cash beyond that, I don't think that would change the queuing.

Arun Jayaram
JP Morgan Chase & Co, Research Division

Great. John, congrats. And I'll miss our colorful exchanges over the years, and good luck in retirement.

John M. Colglazier
Investor Relations Professional

Thanks, Dave [ph].

Operator

And our next question comes from Evan Calio of Morgan Stanley.

Evan Calio
Morgan Stanley, Research Division

Congratulations, John, you'll be missed, and congratulations to Robin in the new role. My first question is really a follow-up to the last one. Is there a limit on how much you will sell? I mean, there seems to be large portions of your portfolio that might not compete for capital versus the 3 Ds here. And maybe can you just explore what are your limits for redeployment in the core areas? And is there -- if asset sales exceed that amount, is there a buyback scenario beyond the investment potential?

R. A. Walker
Chairman & CEO

Well, I think today, as we project what we're going to be trying to do over the coming years, the ability to invest in the Delaware, the DJ and the deepwater Gulf of Mexico gives us exceptional rates of return, assuming oil prices are about where they are, if not a little bit higher. Obviously, if we pull back to $25 a share -- or $25 per barrel rather, that'll have an impact upon our investing. How we will deploy capital at that point, I think we would reconsider. I wouldn't tell you today that we have an answer for that per se, other than we'd spend less. I think we've been very diligent about trying to stay within cash inflows with the way in which we invest and not put our balance sheet at risk. But I'm not really sure today that we see if there's a finite concern associated with investing in the Delaware, the DJ in particular, with respect to having an abundance of cash as long as we're in a $50 to $60 oil price world. So assuming that for a moment, I think you can continue to expect that we will reposition our portfolio more towards oil and away from natural gas, particularly dry gas, and that we believe it compete -- there's inability within our portfolio for dry gas to compete for capital, given what we have in the Delaware, the DJ and the deepwater Gulf of Mexico. And it's really not that we are naysayers on natural gas, it's just we're the beneficiaries in extremely attractive positions in both the Delaware and the DJ onshore. And as we like to remind people, and I'm sure you're well aware of this, if we happen to be a little wrong and natural gas prices go up higher than anticipated, it just makes the Delaware and DJ investments worth even more than what we had originally expected it to be with a more modest outlook for natural gas.

Evan Calio
Morgan Stanley, Research Division

Okay. I think I understand that. And then -- and secondly, you substantially raised the 4Q production guidance on an apples-to-apples basis, 32,000 barrels a day. But is the lift there in enhanced completions and how much is activity? Maybe just walk us through the color and why the U.S. gas volumes are up. A little more color to the 4 guides I think would be helpful.

John M. Colglazier
Investor Relations Professional

Sure thing -- it's Colglazier. Yes, we took the midpoint of guidance from divestiture adjusted from the second to the third quarter for the fourth quarter guidance up about 3 million BOEs, to your point. A lot of that is in the U.S. activity for the oil, driven by the performance you've seen at Lucius, as well the ongoing impact that we have from our Delaware Basin activities that Darrell talked about. And then we also have the corresponding gas and NGLs up as well, so it's really spread throughout the onshore portfolio. And then as you noticed, we also took out a partial lifting out of Algeria as well just from a timing of tanker liftings out there.

Darrell E. Hollek
Former Executive Vice President of Operations

I think from a high-level perspective, if you think about it, we actually set production records not only in Delaware, but in DJ and the Gulf of Mexico this last quarter.

Operator

And our next question comes from Doug Leggate of Bank of America Merrill Lynch.

Douglas George Blyth Leggate
BofA Merrill Lynch, Research Division

John, there's a lot of scared animals out there. So congratulations, good luck. Guys, I wonder if I could just hit the disposal question again. So Al, one of John's parting comments to us is if it doesn't have a D, it's probably not in the portfolio long term, meaning Delaware, DJ and deepwater. I'm wondering if you could just give us a broader kind of view as to whether that's a reasonable characterization as to how we should think about the future simplification of Anadarko. And I'm -- I'd also ask you to elaborate on what that means for some of the noncore international assets. And then I've got a follow-up, please.

R. A. Walker
Chairman & CEO

Well, I think we keep trying to focus investors on the idea that, in the near term, growth and the deployment of capital are focused on those 3 areas you made reference to. It's not that we think that that's the only place we're going to make investments and take consideration in the future, simply because a lot of our exploration, as you know better than most, Doug, is there for option value. So it's very important that we continue to take opportunities where we think it's a good risk rate of return opportunity to simply look for places where we may be able to have option value in the future. Colombia could be just that. Mozambique could continue to be just that. It's not requiring much capital, neither one are that capital-intensive at this point, but it gives us option value for the future. But I think the point we're trying to make is that we are and have been, for most of the last 1.5 years, consistently explaining that we're moving away from natural gas as a focus for investing. We're moving into oil and liquids concentrated opportunities, and that we're trying to simplify the way in which we think about, particularly, our onshore business. And that means that our focus then is going to go into 2 particular plays, the Delaware and the DJ Basin, simply because they provide us the best rates of return within our portfolio that compete for capital better than anything else that we have. And we believe if -- maybe we're just a little bit biased in this, but we believe it creates the best rates of return in our industry for onshore assets. So we have industry-leading assets, we believe, within our portfolio. We also think that for the allocation of capital, the return associated with that, the focus on those 3 areas is particularly important in order to show growth. And that growth will largely be oil growth in the coming years through the balance of the decade.

Douglas George Blyth Leggate
BofA Merrill Lynch, Research Division

I appreciate the clarification. I guess, on that point, my follow-up is an exploration question and it's -- we've now had a couple of well results, I guess, in Côte d'Ivoire. You haven't really elaborated much on

your plans for an asset that you still carry a very large working interest in. So I just wondered if you could give us an update as to your thoughts on how that potential project moves forward.

R. A. Walker
Chairman & CEO

Well, I think you've seen, through the ops report and some of the commentary we provided, we've had good exploration success there. I think the reason that we've not gone beyond that is we're still trying to understand what we believe to be the commercial solution for the discoveries we've had. And in particular, for the natural gas associated with the Paon potential development. I think once we have an understanding of the commerciality of that play, we'll talk more about the development. But at this juncture, I would describe the success we've had as quite good, but that does not correlate yet into a commercial discussion until we have a gas contract that we believe, in fact, gives us that development opportunity. And so that may be the missing link, Doug, that you're seeing as a part of the narrative from us.

Operator

And our next question comes from Scott Hanold with RBC.

Scott Michael Hanold
RBC Capital Markets, LLC, Research Division

John, congrats as well. So you had a pretty good run here.

John M. Colglazier
Investor Relations Professional

Thanks.

Scott Michael Hanold
RBC Capital Markets, LLC, Research Division

Thanks for all your help. If I could dig into your activity here going forward. One thing that was certainly different about this quarter versus last several quarters is that there's not a whole lot of conversation on DUCs and specifically iDUCs. Can you give us your general sense on how you view that -- what was formerly known as iDUCs with respect to how you deploy capital here going forward?

R. A. Walker
Chairman & CEO

Well, I mean, first off, it is DUC season, [indiscernible] be a joke. I think as we move into the balance of the year, I mean, I made reference to the fact that we're going to use some of the capital that -- particularly in the DJ Basin. We've talked about increasing there another 50 completions just based upon the capital we've saved by being more efficient. So as we move through this, we're moving into a higher-price environment. We think, fundamentally, we should continue to see improvement in the quarters ahead. As a result, you'll see us continue to work more to, I'll call it, a working inventory level of drilled but uncompleted. It's not an abnormal level of that. Because I think, as each of the people in this call know quite well, I mean, we have an ongoing sort of like working capital position with respect to drilled uncompleted locations. So it's not like it'll be completely eliminated. But I think given the price environment that we see ourselves in today and projected in the coming quarters, we'll convert more, as appropriate, of that current inventory into completions. But it's not a marked change. I think it's just what we've been trying to say through the course of the year that we will, at the appropriate time, start to convert our drilled and uncompleted locations into opportunities for production. And Darrell, please add to that.

Darrell E. Hollek
Former Executive Vice President of Operations

Yes. Scott, to some extent, we've done that at Wattenberg, where we've actually -- we were down to one rig here in both the second and third quarters, yet we had 1.5 completion crews out there. And so we've gone through some of the -- at one time, what we would've considered iDUCs. But I'll tell you, it's -- it probably makes sense today as our activities pick up and our number of rigs is that we get away from iDUCs, and it's really in inventory. When you look at Delaware, we were at 6 rigs for the summer. We picked up a seventh rig here in the third quarter, and we picked up an eighth already in October and we'd like to pick up a ninth. So as we look at our inventory, it's all becoming one, and we just look at it as wells to be completed. So I'd sort of get away from the iDUCs. We had the same issues going on in Wattenberg where we had, like I said, the one rig, and we now picked up 2 here in October. And it's very likely we'll pick up another rig, if not 2, here before the end of the year as we go into 2017 and move our program forward. So again, I'd just caution you to maybe get away from iDUCs and look at it as just our inventory in front of our rigs.

Scott Michael Hanold
RBC Capital Markets, LLC, Research Division

That's great. And then just to clarify, and you mentioned -- it sounds like a little bit more price-related, but was there a little bit of -- post the acquisition of the offshore stuff, was there a little bit of balance sheet in there? Or is that totally a price-related decision when you decided to kind of work through those iDUCs?

R. A. Walker
Chairman & CEO

No, it's been more price-oriented. If you think back to where we were in early -- in the first quarter and the things that the industry in general is dealing with, I think we, along with others, just didn't feel a need or compelled to bring these into completion until we believed it was appropriate from a standpoint of where prices are now. You could argue one way or the other whether you think that was a good strategy or bad. I think from our perspective, we thought it was a much better strategy to bring these into completion when oil is around $50 versus $30.

Scott Michael Hanold
RBC Capital Markets, LLC, Research Division

Okay. That's great. And then as a follow-up, Constellation, that acquisition in the offshore. That looks pretty interesting. Could you give a little color around that opportunity? What you all think you acquired in terms of what this thing can produce and the cost of the doing something like that?

R. A. Walker
Chairman & CEO

Well, one of the attractive things about the Freeport McMoRan Oil & Gas transaction, beyond being able to increase if not double our position in Lucius, was being able to look at the infrastructure that we were taking on for additional tiebacks that were currently in inventory from Freeport, or through being able to provide production-handling agreements to third parties who need to come across the platform in order for something to be productive. I mean, we've gone from 7 operated facilities in the Gulf of Mexico to 10 now. Our ability to leverage those into opportunities like Constellation, I don't think that's going to be a one and done. I think we're going to see more of that. And maybe Darrell, if you don't mind, elaborate just a little bit.

Darrell E. Hollek
Former Executive Vice President of Operations

Yes. In the case of Constellation, that's the old Hopkins discovery by BP. And where they stood at the Pliocene, so it's not a very expensive development, but it was hard to do a greenfield there. And with our Constitution platform just miles away, we were able to leverage our way in there for a third working interest, and we gave them a PHA across our facility. And so you'll see us drilling our first development well here next year in '17, and we should see production in '18. But again, you're talking Pliocene, we would expect these wells to produce 15,000 barrels a day-type wells. Exactly how many we'll need to drill,

we haven't worked through that. But it was a great opportunity for us. And like Al said, because of our infrastructure, it provided a great opportunity for us to sort of leverage our way into this. And so we're the operator, with BP being the other 2/3.

Operator

And our next question comes from Brian Singer of Goldman Sachs.

Brian Arthur Singer
Goldman Sachs Group Inc., Research Division

John, congrats on your career and responsiveness to all of us. Al, your acreage position in the Delaware in addition to the West ownership puts Anadarko in a unique position to discuss the infrastructure needed to ramp up in the Delaware. And wondered if you could give us an update on the midstream CapEx that you see needed in the Delaware to meet Anadarko's needs, whether you see any pipeline or gathering constraints that Anadarko and others ramp up seemingly pretty aggressively. I mean, how the differences made -- how there may be differences or similarities for Anadarko's specific experience versus industry's?

R. A. Walker
Chairman & CEO

Well, Brian, thanks for asking that question. I think what we did in the DJ Basin was, for us, a bit of a road map for what we're trying to do in the Delaware Basin. The difference being the Delaware Basin, and Don Sinclair is using a lot of third-party money, and by that I mean we're transmitting or processing volumes for third parties. As a result, it's not as capital-intensive net to Anadarko as it was in the DJ Basin where we were largely, if not, in some cases, exclusively the equity behind the system. So consequently here, we're a bit more of a third-party provider of processing and transmission services or gathering. And consequently, the net capital requirement for Anadarko is a lot less as we take what we believe is the playbook in the DJ and put it work in the Delaware. That's why you've seen us make acquisitions like we did just about 2 years ago. That's why you've seen us organically add to what we have as well as what we acquired. And that's why we've been fairly focused on these various ramps we planned to increase our production and processing capabilities. Darrell has a fairly aggressive plan for drilling upstream dollars behind these plants, and he has, I'd say, a more modest need on capital as it relates to midstream. So Darrell?

Darrell E. Hollek
Former Executive Vice President of Operations

Yes. The only comment I'd make, it's not without a challenge. Whether it's being done by APC Midstream or West, we are investing in the infrastructure. And where we can take advantage of third-party opportunities, we're doing it. But if you -- again, going back to the offshore part, you see the scattered fashion in which we're trying to delineate the field, it does create some challenges on the facility side. And so we'll still be trucking some of our volumes. But the extent we can, it's giving us the opportunity to really extend that footprint. I think from a bigger-picture standpoint, as we look into '17, your question on capacity constraints, we don't see it. We think we have no issues getting out of the basin in '17 even with the aggressive program we'd probably come into the year with.

R. A. Walker
Chairman & CEO

And as with all the yield streams Darrel is making references to. It's not just gas, it's not just natural gas liquids, it's not just oil, we think we have good takeaway capacity with each of the principal yield streams.

Brian Arthur Singer
Goldman Sachs Group Inc., Research Division

Got it. And then, I guess just shifting more to the outlook for 2017. I know that we're still some months away from when you would have your guidance, but can you just kind of talk about how you're thinking about how the capital program and, ultimately, your expectations for growth would differ if, let's say, we're

sitting here in 3 or 4 months at a similar oil price to the $46 to $47 we're at versus if we are $5 or $10 higher?

R. A. Walker
Chairman & CEO

Brian, I don't think it will really affect the principal investing strategy that we were talking about this morning. And I don't mean to sound like a broken record, but it's going to be Delaware, DJ and deepwater Gulf of Mexico that's going to take on the lion's share of our capital in, let's call it, a fairly static or ceteris paribus environment for operating conditions. So consequently, our ability to put more capital to work, either through cash flow or through cash on hand, we have a lot of flexibility. I'm real proud of what Bob Gwin and what our corporate development folks working with our asset teams have been able to accomplish with the monetizations we've achieved to date and things we hope to do in the future. So whether it's cash flow or the use of cash at a point in time, we have the capacity today to do things that we've talked about wanting to be in a position to do going into '17, believing that fundamentally, we should see better price support for oil. And if that's the case, I think you'll see us cycle the cash faster. You'll see us likely increase the types of things we've been talking about in the Delaware Basin first, and I think Darrell probably would stand up rigs in the Delaware ahead of DJ to some extent. There's a lot of opportunity we see in the near term in the Delaware before we go into full development mode. But Darrell, please add to that.

Darrell E. Hollek
Former Executive Vice President of Operations

No, I think you're right. And that's why I commented we've picked up that eighth rig in Delaware and look to pick up a ninth here shortly. But it's not taking away from DJ. We got the 3 rigs now, we'll probably pick up a fourth and fifth rig potentially by the end of the year. We've gone out and said that we look to grow oil 10% to 12% in a $50 to $60 world. If it's a little bit less than that, I would guess it would just drop a little bit more. It just depends on how we're going to spend the cash on hand. But in either case, I think you can expect between the 3 Ds that we'll see a considerable oil growth over the next 5 years.

R. A. Walker
Chairman & CEO

Yes. I know you know this, but we have a very high oil cut in our position in the Delaware. This is not a lot of natural gas, a little bit of liquids. This is a big cut that's oil that gives us tremendous economics at the well head, and as a result, gives us a really good cash flow to recycle. I don't think that we, today, have a better position to put capital to work as a company. And I'd argue that I'm not sure in an industry today at, call it, $50, anyone has a better position onshore than what we've got in the Delaware Basin.

Brian Arthur Singer
Goldman Sachs Group Inc., Research Division

Got it. So I think what we're hearing here is that there would be some flexibility at a $55 versus $45 oil price. But maybe not a -- the fact that you'll have a lot of cash on hand, you may -- that may lead to a more stable CapEx program regardless of the oil price.

R. A. Walker
Chairman & CEO

I'd say it's steady to up.

Operator

And our next question comes from Charles Meade of Johnson Rice.

Charles Arthur Meade
Johnson Rice & Company, L.L.C., Research Division

I wonder if you could lay out for us what you think the Mozambique success would look like in 2017. What milestones or progress you think can -- we can look forward to for that?

R. A. Walker
Chairman & CEO

Well, I appreciate you asking the question. It's one of the things a lot of times that is not well understood, because there's not that many moving parts that we are looking for. If you think about trying to be a fairly compartmentalized thinker, in 2016 into '17, there are not that many moving parts that we're looking for in terms of trying to accomplish. And I might let Mitch, if he doesn't mind, elaborate on that. But it's not like we're trying to do everything at once. We have a very compartmentalized view of what needs to be done ahead of us.

Mitchell W. Ingram
Executive Vice President of International, Deepwater & Exploration

Thanks, Al. Charles, so with the support of the Mozambican government, we made significant progress during this year really on the important government agreements. The suite of agreements that we term legal and contractual framework have been socialized with the government, and we expect approval of those in the near term. We're also well advanced with our planning and preparation for reassessment. We submitted our reassessment plan to the government in June. And after a few months of discussions with the government, that plan has been accepted, and we, again, await approval of the plan in the near future. When both of these elements are approved in terms of the legal and contractual framework and reassessment plan, however [ph], we will then progress further the -- with our buyers, converting our Heads of Agreement to sales and purchasing agreements, and we'll also take forward all the arrangements for project finance. So our immediate priority just now is to gain approval of the suite of agreements and reassessment plan, and then we'll progress the further work towards FID.

Charles Arthur Meade
Johnson Rice & Company, L.L.C., Research Division

Got it. That's helpful detail, Mitch. And if I could ask you as a follow-up, going back to your theme of the 3 Ds, Al, I feel like a lot of the discussions have been around the DJ and the Delaware. But I'm wondering if you could talk about the prospects to apply more investment to your international deepwater portfolio. My impression is that exploration projects, such as what you have going on in Colombia, don't necessarily yield to increased investment. But maybe that's -- maybe you have a different point of view. And/or alternatively, are there opportunities for you guys to replicate the kind of deal you did with FCX, either in the Gulf of Mexico or somewhere else in the world?

R. A. Walker
Chairman & CEO

Well, if I could just use the comment sort of in a broad sense. We don't look at exploration as sources in the near term for production. That really our exploration activities are our option value for the future, and as a result, we really do see things that we're doing today in Colombia as having option value. Now once we determine whether or not we have a commercial opportunity, we want go to development, then we start to figure out where it is in the queue over a time horizon for production. But the reason for a lot of the answers today about where we put incremental capital, when you've got the positions that we do onshore in the Delaware and the DJ, that provides us extremely attractive rates of return and it also gives us the type of on-site growth that we find very attractive from a standpoint of how we enhance shareholder value. Longer term, we need to continue to find ways to look for new opportunities. What we see in Colombia excites us, both in terms of what we're currently drilling as well as what we see ourselves drilling through the balance of the decade. So that option value is something that we'll continue to look for. There are other places, and certainly the Gulf of Mexico, as you made reference to the FCX deal. I don't know if there's another one around the corner. Bob Gwin and a lot of people did a really good job with that one. We're certainly in business. If there are other people that find of Gulf of Mexico not as attractive as we do, we'd be happy to try to buy some more assets for 1.5x next year's cash flow.

Operator

And our next question today comes from David Heikkinen of Heikkinen Energy.

David Martin Heikkinen
Heikkinen Energy Advisors, LLC

I was thinking about Mozambique and kind of the path forward and was considering, do you think that you're realization and pull-forward of value and the subsequent reduction of working interest to the 26.5% has actually impacted any potential buyer and moved Anadarko more towards a higher chance of developing the asset?

R. A. Walker
Chairman & CEO

Dave, as you've probably had more conversations with people on that than I have, I can honestly tell you no one's ever had that conversation with me. So it'd be pure conjecture on my part. I don't know that I even could come close to telling you whether or not I have a view on that. I know that when we executed the 10% working interest sell-down, it was a part of the playbook that we did not want that much working interest if we were to take FID. Again, I sound like a broken record this morning, but Bob Gwin did a great job selling that down to ONGC. As a result, today, we still, even with all the capital we've spent in Mozambique, if you just think of it on a project-level basis, we're still $300-plus million to the positive in terms of what we've invested there versus what we've taken in. So consequently, again on a project level basis, we've done a pretty darn good job of managing our exposure from a cash or capital perspective and still give ourselves a lot of option value around whether or not we take FID. If someone decides that they like it better than we do or they see more value than we do, we're not married to it any more than we are married to any other asset in our portfolio. But we do believe today that we have the skills, the capability, and we also believe the opportunity, if we take it to FID, for it to be a game-changer for our company. And so consequently, Mitch looks at this every day with a very balanced view of what's best for Anadarko in the next decade.

David Martin Heikkinen
Heikkinen Energy Advisors, LLC

Cool. On another consideration, but the script in the DJ was asset swaps and then drilling longer laterals has been important in developing all the oil plays. I look at your Delaware position and then the purchase price of what assets they're transferring for, and your comments about higher and higher values, that you have some incongruity of -- or juxtaposition of ability for Anadarko to assign that value. Can you talk to us about your ability to drill longer laterals as opposed to single-section laterals, keeping kind of the crosshatch pattern on your assets, and then the likelihood of swaps?

R. A. Walker
Chairman & CEO

Well, as you know, I mean, that play -- or all of that, because it's not just one particular zone, there's many, as we talked about this morning. It's a stack pay opportunity, and consequently, there's lots of things that we're looking at today that will be a part of the future. But the one thing that we're working on the most is the Wolfcamp. So just focusing on the Wolfcamp, yes, we would love -- as these things start to settle out in the Delaware Basin, thinking about blocking up with people and making it a little more attractive. Given the velocity of change in the basin, it makes it a little more difficult today. So I think sort of just in the evolution of the basin's development, it's unlikely we're going to see people doing what we did in the DJ with Noble, and doing something that was a win-win for both of us. But I'm sure Darrell and his folks, Brad and others, have been trying. It's just it's early in the evolution or lifecycle of the basin's development.

Darrell E. Hollek
Former Executive Vice President of Operations

Yes, Dave, this is Darrell. There's no doubt we have better economics as we get into the longer laterals. And I think if you look at the program this year, more than 60% of our wells were in excess of 7,500 foot laterals. And so we have done trades to give us that ability, and we continue to work trades. And some of

them aren't big enough to come out and talk in the market, but those things are happening every day. To Al's point, they're not always easy because there's -- some of these leases can be burdened in different ways, and so we got to work through that. But I think it's in everyone's best interest to do that, and we're finding a lot of people cooperating. So we'll continue to work it because, again, in an ideal world, we're going to be drilling 10,000-foot laterals. It's better economics.

David Martin Heikkinen
Heikkinen Energy Advisors, LLC

How much of your acreage now is single-section prone? I guess I'm trying to think about a split of [indiscernible] the longer lateral available.

Darrell E. Hollek
Former Executive Vice President of Operations

Yes. I don't know that I have that exact number. Like I said, there are more than 60% of our wells this year being drilled that are in excess of 7,500. So I don't know that it's important where we are today as much as it will be where we're going in getting some of these trades consummated.

Operator

And our next question comes from Bob Brackett of Bernstein.

Robert Alan Brackett
Sanford C. Bernstein & Co., LLC., Research Division

Congrats, John. And quick question on the Delaware. You got a JV partner out there. How does that partner's goals align with your goals? How does capital allocation work? Is that a relationship that's built to last? Or are there ways around that relationship?

R. A. Walker
Chairman & CEO

Well, it's certainly an atypical relationship in the sense that our partner there stepped into the position by virtue of an acquisition they made from Chesapeake. Consequently, it wasn't like this was contemplated day 1 that we would be in a joint venture together. So far, I have nothing but compliments to pass on. And Shell has been a good partner. We've talked to them on many occasions about things that we can do and improve efficiencies out here, and I think they've been very receptive. So I wouldn't paint them with a brush that they are a major and, consequently, unable to understand how to harvest value from the Delaware Basin.

Robert Alan Brackett
Sanford C. Bernstein & Co., LLC., Research Division

Okay. Great. And then a follow-up on exploration. In a sense, you've got a fairly obvious runway of high returns in the DJ and in the Delaware and in tiebacks in the Deepwater Gulf. When you're going out doing pure exploration, are you incented to go sort of high risk, high rewards? So in other words, if you discover a fairly middling discovery, it might not compete for capital, but a big blockbuster would. Does that guide your exploration strategy?

R. A. Walker
Chairman & CEO

I think our exploration strategy has always been one where we want to make sure that we're taking opportunities statistically to give ourselves a chance of things that are needle movers. And that's what we've historically done, I think we'll continue to do that. We have 16 million acres offshore Colombia because we see a lot of prospectivity there and a lot of running room if we're correct. So I think, philosophically, the types of things that we will do in exploration, whether it's in the Gulf of Mexico or internationally, are fairly similar. And the Gulf of Mexico today, given the price environment that we're in, if we don't have tieback to existing infrastructure, we're not out trying to drill opportunities that require

greenfield development as a result. So that may be where the 2 are a little bit different because we're dealing with a much higher cost per well. Typically, we're in a pre-salt environment with the exploration opportunities. Whereas in many cases, internationally, we're post-salt, where the cost to drill a well is substantially less. And so therefore, if we're successful, the development drilling associated with any development opportunity is a little more economically positive from the standpoint of the price environment. So I don't think, from a standpoint of Anadarko's view of exploration or my hope for what we're able to deliver on exploration, is any different today than it would have been in 2013 or '14 in a different price environment.

Operator

And our next question comes from David Tameron of Wells Fargo.

David Robert Tameron
Wells Fargo Securities, LLC, Research Division

John, best of luck to you. There's a reason you won that IR award multiple years for Best IR. You made all our jobs easier, so we appreciate all the help you've given us over the years, and best of luck.

John M. Colglazier
Investor Relations Professional

I'll miss you.

David Robert Tameron
Wells Fargo Securities, LLC, Research Division

Al, going to the DJ, or Darrell or whoever wants to talk about this. If I just look at your production over the -- just over the last year, the oil kind of stayed flattish, NGLs and gas have continued to grow. So I guess a 2-part question. One, should we see that reverse as the rig count starts to climb again? Or is that just a function of the slowdown of drilling and some of the gas GORs climbing in the outyears? And then second, I know some of the other operators may have potential issues next summer as far as it relates to line pressures up more in that the DCP, the middle to the upper part of the basin. How do you guys -- I assume you're okay with your infrastructure, given what you did a few years prior, but how do you -- how would you answer those 2 questions?

Darrell E. Hollek
Former Executive Vice President of Operations

Yes. I think as you look into next year, we don't see a problem like -- again, one of the advantages to West and going into Saddlehorn, we've got White Cliffs, we've got access out of the basin. We've got Lancaster plants. We're in pretty good shape. So we don't actually see any of those pressures that you're talking about. In terms of the well count and maybe the oil ratio, I do think you're seeing the impact of the lack of capital spend this year in Wattenberg. And so as the field continues to produce, it does go to a higher GOR. And generally, we've been able to offset as we brought in -- drill more wells and put new wells on because they're higher oil cut. So if you just think about we went 2 quarters in a row with 1 rig, so we don't have a lot of new production coming on. I will have to say that the field guys did a fantastic job hitting the records they did. Yes, a lot of it was gas, but I can tell you that the peak we hit in the third quarter after such little activity was a fantastic accomplishment on their part. But as we stand up more rigs and we bring more wells online, you're going to see that turn again, and you'll -- you should start seeing our oil production go up. It may not be by year-end or even first quarter, but I think we would anticipate next year to reverse that trend and you'll see the oil production start rising again.

Operator

And our next question comes from Ryan Todd of Deutsche Bank.

Ryan M. Todd
Deutsche Bank AG, Research Division

Maybe a couple details on the Permian. Can you talk a little bit -- I mean, we talked some about longer laterals. What are you seeing in terms of the productivity increases on the longer laterals? Should we expect kind of a constant EUR per lateral foot versus what you've communicated on the singles? And then maybe for spacing in the Wolfcamp, what are you currently assuming kind of as the base case in the Wolfcamp spacing? And then what are you currently testing? I know you're talking about going deeper into the Lower Wolfcamp. I mean, where do you think we may eventually go in terms of wells per unit in the Wolfcamp there?

Darrell E. Hollek
Former Executive Vice President of Operations

I'm trying to figure out where I want to start on there. With these laterals, I mean, again, we're going to be pushing to do those. But some of the things that are increasing our EUR has to do with the type of completions we're doing. At one time, our standard completion was sort of 1,400 pounds per foot. Today, I would call that standard completion 2,500 pounds per foot. And I can tell you we're experimenting with the sand and the water rates, double that. So we're not sure where that's going to go. We probably have more to deliver or more to talk about in March, but we are seeing the increasing EURs as we continue to put more sand and water. And so we'll see where that no return is on that, but we're seeing good things right now. And that's really because of our increasing EURs at this point, it's just the change of our completions. I forget, your second question was...

Ryan M. Todd
Deutsche Bank AG, Research Division

It was on spacing in the Wolfcamp. Where do you think you may eventually go in terms of how many wells are you able to put into a unit in the Wolfcamp? What are you testing right now?

Darrell E. Hollek
Former Executive Vice President of Operations

Well, we're doing a number of tests. We got a 20-well test going. And so a lot of that is going to be driven by economics and to the extent you have interference. So I think it's just too early to tell right now because, again, if you look at how we're drilling these wells, we're not doing too many tests where there's big clusters. We do have the 120-well test going on that should give us a lot of information. And again, I would say, by March, hopefully we'll have more to tell you on that.

Ryan M. Todd
Deutsche Bank AG, Research Division

Great. Maybe can I leave with one quick one on Shenandoah? I mean, I see you made an on-concept selection of a semi-sub. Any thoughts around the concept selection, maybe the path to potential FID? And if you think -- can a standalone development like Shenandoah really compete with the tieback opportunities you have in the Gulf? And I'll leave it there.

Darrell E. Hollek
Former Executive Vice President of Operations

Yes, this is Darrell. We had a couple of competing options there, and so we're really in the pre-FEED. We're not at a point to make FID election at this point. But we felt that, overall, the semi-sub was going to garnish us a little bit more flexibility in what that answer looked like. So we decided just go down to the one option as we continued our pre-FEED efforts. But we're far from making an FID decision today. We'll be look at drilling that 6th well here by the end of the year, we'll be getting on it. So we look forward to seeing those results.

R. A. Walker
Chairman & CEO

I think it'd be fair to say that as we contemplate sanctioning Shenandoah, we will be mindful of what we can do on the margin with the capital. And it'll be an allocation like it would be for anything, where we're looking at what the rate of return is as well as the cash-on-cash return. A lot of times, our industry is

very focused on rate of return and not cash-on-cash because, as everybody knows on this call, it's great to have an internal rate of return that's 50%, but if you get the cash back in the year and you're pretty much done, that's a hard treadmill to continue. So we want a cocktail or a mix that gives us really good rates of return with really good cash-on-cash characteristics. So there could be a role that Shenandoah or another option like that plays in our portfolio. So I don't want to leave people with the view that allocation of capital is purely an IRR-driven derivative. Consequently, we have a portfolio to run and we'll consider whether or not at the time of sanctioning, it makes sense to commercially develop Shenandoah along with our partners or not.

Operator

And our next question comes from Paul Sankey of Wolfe Research.

Paul Benedict Sankey
Wolfe Research, LLC

John, congratulations. Can I just sort of repeat the question: How does Exxon's move change Mozambique?

R. A. Walker
Chairman & CEO

Well, I know nothing more than what -- probably what you do. I may not know as much as you do. All I know about Mozambique and ExxonMobil is what I read in the paper. All I can say to that is simply is ExxonMobil words [ph] have contemplated and concluded a transaction with ENI and the government. We will sit down and understand better what their plan of development is. Today, it'd be pure conjecture on my part, Paul, to weigh in on that, simply because all I know is what I read in the paper.

Paul Benedict Sankey
Wolfe Research, LLC

Understood. And again, this is something of a follow-on question. But the recent acquisition you made, could you just give us the very latest on where you stand with that deal and how it's changed things for you?

R. A. Walker
Chairman & CEO

Well, nothing's really changed. I think we've always projected a fourth quarter close. We seem to be very much right on the time line or track that we had anticipated. Consequently, we see this as a December close. We found nothing in the closing process as concerning. The folks at Freeport-McMoran have been exceptional to deal with. And as a result, we anticipate getting a close and having it part of Anadarko as we move into 2017.

Paul Benedict Sankey
Wolfe Research, LLC

Great. So the -- this sort of noise that we heard around debtholders on the Freeport side is not a concern to you?

R. A. Walker
Chairman & CEO

It's not our assessment that that's our issue. I think that's an issue between FCX and the fixed income investors and the conversation they're having. It's our assessment that, frankly, that does not create an impediment for us to close.

Operator

And our next question comes from John Herrlin of Societe Generale.

John Powell Herrlin

Societe Generale Cross Asset Research

Happy hunting, John. Regarding Colombia, how long will that well take to reach TD?

Ernest A. Leyendecker
Former Executive Vice President of Exploration

John, this is Ernie Leyendecker. We're not there yet. We're just finishing up our program in West Africa right now, and we expect the rig will be demobilizing from that prospect over there and get to Colombia within the next month or so. We've got a 2-well program set up there. We're making strides in reducing the time to drill the wells in Colombia after our initial campaign. So the next well we'll get to, we'll actually top set the first well and go over to drill a Purple Angel well, and that's probably going to be about a 45-day well, give or take a few days. And as we carry into the new year in 2017, we'll move over and drill another prospect in a similar section there called Gorgon. So they're not long wells. We're continuing to get up the learning curve on drilling wells in Colombia, and we look forward to seeing those results. But what I would remind you of a little bit is we're really looking forward to getting over to the coal area where we shot the 30,000 square kilometers of 3D, and we've just got a fast-track volume in, looking for the final volume in by the end of next year. And our goal is really to accelerate drilling activity over in that big chunk of acreage in the ultra-deepwater offshore in Colombia. Looking for oil, of course, there. And very hopeful that we've got a thicker source rock and buried a little bit deeper, so we're anxious to get over there on that particular acreage.

John Powell Herrlin
Societe Generale Cross Asset Research

One other one. Al, have you been surprised about the resiliency of the natural gas sales market?

R. A. Walker
Chairman & CEO

Well, I've been a natural gas bear for quite a while. I think we always thought that gas would find its way up around $3, and we'd find the ceiling there. And to a large extent, that's been correct. I mean, we see -- we've always believed around $3 that there was just an impediment from a demand standpoint for now. But I think it also is the reason a lot of people -- in January, we talked about selling our natural gas properties and people kind of looked at me cross-eyed that we would actually have a market for it. There's been a lot of very successful private equity people that have taken a view on natural gas and done quite well with it. I think for a company like ours that has the assets that we do and our access to oil and liquids that we do, consequently, it's not really in our best interest to pursue natural gas. It doesn't give us the same wellhead margin. It doesn't give us the same ability to have scalability. And the returns, coupled with the scalability, just always tilt in the favor of the DJ and the Delaware for us. John, I just have to say, I don't mind being wrong, but I think our view is that it would take natural gas to approach $6 before it would probably displace our interest investing in oil, and I don't see that happening.

Operator

Our next question comes from Pearce Hammond of Simmons Piper Jaffray.

Pearce Wheless Hammond
Piper Jaffray Companies, Research Division

Congrats, John. You'll definitely be missed. And congrats, Robin and her team on her new role. My first question, are you currently experiencing any increase in service cost? And what are you anticipating for service cost inflation for next year?

Darrell E. Hollek
Former Executive Vice President of Operations

Yes, Pearce, this is Darrell. I would say not. To the contrary, I think as the year went on, we were pleasantly surprised that we were able to get some of the service cost down a little bit. Now I think that's leveling out. But as we've stood up more rigs and contracted more equipment, we're not really seeing that

pressure today. So my guess is as oil continues to go up, if it gets up around $60, we may see some of that. But I think there's enough equipment still on the ground and crews willing to work and get part of the business that we're not going to see that pressure for a while.

Pearce Wheless Hammond
Piper Jaffray Companies, Research Division

Great. Then my quick follow-up is, is Jubilee exceeding your expectations for the second half of the year? At Q2 earnings, you had stated that you thought that second half of the year, Jubilee would average about 85,000 barrels a day. Q3 was about 91,000 barrels a day, and it looks like you took up your '16 full year production guidance [indiscernible].

Darrell E. Hollek
Former Executive Vice President of Operations

No, I would say that we're very pleased with what's happening there at Jubilee. We're continuing to work through the turret issue. But the shuttle tanker system that they set up is working well, and we're on our way to trying to get to a permanent fix. We're still trying to get a temporary fix done by the end of the year. But I would say all-in-all, the activity there are going as well as we would've expected.

Operator

And our next question comes from Jeffrey Campbell of Tuohy Brothers.

Jeffrey Leon Campbell
Tuohy Brothers Investment Research, Inc.

First, I want to say happy trails to John and have a lot of fun.

John M. Colglazier
Investor Relations Professional

Thank you.

Jeffrey Leon Campbell
Tuohy Brothers Investment Research, Inc.

Al, you talked earlier about the importance of monetizing the nat gas at Paon. But I was surprised by the large oil cut and the drill stem test. And I was just wondering, is that typical of the play as a whole? Or is there quite a bit of mix variability across the field?

R. A. Walker
Chairman & CEO

Well, we're very fortunate to have liquids in the system, and so you're right for highlighting that. I do think, though, that our commercial decision will likely hinge on just the type of gas contract we can enter into. Because without that, the oil becomes a by-product. You really need to be able to move the gas into a market at a price that's attractive in order to evacuate the liquids.

Jeffrey Leon Campbell
Tuohy Brothers Investment Research, Inc.

Okay. Understood. And my quick follow-up is the ops report highlighted Heidelberg well. It appears to define the northern limits of the field. I was just wondering how was this result relative to your predrill expectations.

Darrell E. Hollek
Former Executive Vice President of Operations

Yes. This is Darrell. Well, I can tell it was a disappointment. But probably more than that, it was really a surprise. I mean, based on the reprocessed seismic that we have, we fully expected this to be good. So it's sort of hurts the northern end of that field. I can tell you, consequently, we've -- we're sidetracking

that well now close to the discovery well. So we know it's good there. And so the thought there is we'll complete this well, we'll have it on the first quarter. So we really see little impact in '17 from a volume standpoint, but we got to remap this thing and try to better understand it. It may have a reserve impact, and we'll work through that before the end of the year. But I think as far as we're concerned, we don't see an impairment on our side based on our investment here. But it was truly a disappointment and a real surprise as to this being wet there. So it sort of takes away from the northern end of the field, but we still are very high on the south end of the field in Heidelberg as well, so that will be future wells.

R. A. Walker
Chairman & CEO

And Darrell's right. Just take one other comment. Yes, we've been surprised by it, but I will say that if we end up finding ourselves having to take a reserve right now, it will be very modest. The reason we've not impaired to-date, if you recall, we promoted out the development drilling here, so our cost basis here is a lot different than our partners. And therefore, in addition to the cost base, we also have the advantage of the way it's carried from an impairment standpoint or reserve adjustment if one's needed. So in the scheme of things for us, it's a very small adjustment if it turns out to be the case.

Operator

And this concludes our question-and-answer session. I'd like to turn the conference back over to the management team for any closing remarks.

R. A. Walker
Chairman & CEO

Well, as I said at the start, it's a bittersweet day. We had a great quarter. A lot of people did a wonderful amount of work this quarter and this year for what has been a very turbulent period in our industry's colorful history. But we are going to miss John. He's done, as I said earlier, a tremendous job. He's been a thought leader. He's been someone who, I think, has taken our industry in terms of how Investor Relations should be conveyed and conducted to a level that has not been, in my estimation, done previously.
It's been a pleasure for the 10 years that he's been on the job to work with him, and we have every confidence that he has got Robin ready to go. And as they say in East Texas, she is sitting on go, and we're ready for her to step in the jobs that have gone [ph] before her. So it's bittersweet today. We're all going to miss John. But I will promise you, she is capable of stepping in as he's trained her quite well, and she's very capable in her own regard. So John, we're going to miss you. And Robin, look forward to working with you next quarter.

And thank you, everybody, for today. We'll talk to you soon. Bye-bye.

Operator
And thank you, sir. Today's conference has now concluded, and we thank you all for your attending today's presentation. You may now disconnect your lines.

Exhibit 116

THOMSON REUTERS STREETEVENTS

EDITED TRANSCRIPT

APC - Q4 2016 Anadarko Petroleum Corp Earnings Call

EVENT DATE/TIME: FEBRUARY 01, 2017 / 02:00PM GMT

OVERVIEW:
Co. reported 4Q16 results.

Exhibit
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CORPORATE PARTICIPANTS

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Al Walker *Anadarko Petroleum Corporation - Chairman, President & CEO*

Darrell Hollek *Anadarko Petroleum Corporation - EVP of Operations*

Bob Gwin *Anadarko Petroleum Corporation - EVP of Finance & CFO*

Scott Moore *Anadarko Petroleum Corporation - VP of Worldwide Marketing*

Mitch Ingram *Anadarko Petroleum Corporation - EVP of Global LNG*

Ernie Leyendecker *Anadarko Petroleum Corporation - EVP of International and Deepwater Exploration*

CONFERENCE CALL PARTICIPANTS

Evan Calio *Morgan Stanley - Analyst*

Arun Jayaram *JPMorgan - Analyst*

Doug Leggate *BofA Merrill Lynch - Analyst*

Scott Hanold *RBC Capital Markets - Analyst*

Ed Westlake *Credit Suisse - Analyst*

Brian Singer *Goldman Sachs - Analyst*

Charles Meade *Johnson Rice & Company - Analyst*

Bob Brackett *Sanford C. Bernstein & Co. - Analyst*

John Herrlin *Societe Generale - Analyst*

David Heikkinen *Heikkinen Energy Advisors - Analyst*

Ryan Todd *Deutsche Bank - Analyst*

PRESENTATION

Operator

Good morning, and welcome to the Anadarko Petroleum Corp's fourth-quarter 2016 earnings conference call.

(Operator Instructions)

Please also note today's event is being recorded. I would now like to turn the conference over to Robin Fielder, Vice President Investor Relations. Please go ahead.

Robin Fielder ***- Anadarko Petroleum Corporation - VP of IR***

Thanks, Rocco. Good morning, everyone. We're glad you could join us today for Anadarko's year-end 2016 conference call.

I'd like to remind you that today's presentation includes forward-looking statements and certain non-GAAP financial measures. We believe our expectations are based on reasonable assumptions; however, a number of factors could cause results to differ materially from what we discuss.

We encourage you to read our full disclosure on forward-looking statements and the GAAP reconciliations located on our website and attached to yesterday's earnings release. Additionally, we have provided detail in our fourth-quarter operations report on our website.

At this time I will turn the call over to Al Walker, and we will open the lines in a few minutes for Q&A with Al and our executive team following his remarks. Al?

Al Walker *- Anadarko Petroleum Corporation - Chairman, President & CEO*

Thanks, Robin. It's certainly great to have 2016 in the rearview mirror. It's even better that we accomplish what we did so that as we start 2017 we have the wind at our back.

It was an incredibly challenging year for our industry. However, as I stated last year about this time, during difficult times, a company's culture, its employees, track record and approach to value creation will separate winners from losers.

I think as I look back at that and take advantage of having the ability to look back and think forward, I believe our results say it all. I think those attributes that we thought a year ago were very important have positioned us today incredibly well.

Our employees over the last 12 months were the difference, and did an incredible job. Through their efforts we've exceeded our sales volumes and expectations on an adjusted basis for the divestures that you are aware of, and we did a while keeping our capital investments within guidance.

Our BOE lease operating expenses were particularly attractive, as we those below $3 every quarter during the year as a result of lower costs and higher volumes. We drilled six successful deepwater exploration and appraisal wells in 2016, and our balance sheet is much stronger today as we refinanced and reduced debt while improving our cost structure on a going forward basis by about $800 million annually.

Perhaps the most significantly -- perhaps most significantly through our efforts we high graded our activities and our active portfolio management have left us with an extremely attractive footprint. We've concentrated our US onshore activities and our industry leading oil levered positions in the Delaware and the DJ.

Through the acquisition of Freeport's Gulf of Mexico properties, we have the largest operated infrastructure in position in the deepwater Gulf today, creating a tremendous cash generating machine to fund future growth. We've built a strong cash position with more than $4 billion of monetizations closed during 2016. And I'm sure as you've probably noticed, an incremental $3.5 billion have been announced and expect to be closed during the first quarter.

From a global perspective, we're beginning to see some encouraging demand improvements and supportive supply actions. And I continue to feel strongly that we have a very good chance to see an average WTI oil price in 2017 of $60.

When you combine our cash position with improving cash flows, we expect to be in an advantageous position to fund growth in both the Delaware and the DJ, as well as the deepwater. We also expect we had the potential to add to these positions through bolt-on acquisitions to further enhance the scale and to capitalize in a competitive advantages. The three Ds give us a clear line of sight to short-cycle oil investments with attractive wellhead margins that will help drive our expected five-year compounded annual growth rate for oil of 12% to 14%, assuming a $50 to $60 oil price environment.

Later this month we will recommend a capital program to our Board that reflects our confidence that Anadarko can deliver attractive growth and value through the balance of this decade and beyond. As I've said in other venues, I've been with Anadarko little more than 11 years and I believe we are better position today than at any time during my tenure to deliver differentiating results.

We look forward to going into greater detail about our capital plans and expectations for 2017 when we provide guidance on March 7 and host our investor conference call on the 8th. With that, let me open it up for questions.

QUESTION AND ANSWER

Operator

(Operator Instructions)

Evan Calio, Morgan Stanley.

Evan Calio *- Morgan Stanley - Analyst*

Good morning, guys.

Al Walker - ***Anadarko Petroleum Corporation - Chairman, President & CEO***

Good morning.

Evan Calio - ***Morgan Stanley - Analyst***

You guys have been very active portfolio managers and you'll be broaching $6.7 billion in cash following closing of the Eagle Ford Marcellus sales in 1Q. Maybe a few questions around that. First, any color or forward outlook to asset sales or general dimensioning for 2017?

And secondly what's the general strategy for capital reallocation or capital return here? Assuming strip-like pricing, what should we expect cash balances, say, 12-plus months or some kind of medium-term level?

Al Walker - ***Anadarko Petroleum Corporation - Chairman, President & CEO***

Evan, let me try to address the question of more asset sales. I think we've probably done a tremendous amount in that area, not just in the last 12 months but over the last two years. I think as we continue to think about our portfolio, things that feed on capital are the things that we see ourselves wanting to retain.

As you look at us today, to be somewhat repetitive, I think the Delaware, the DJ and the deepwater Gulf of Mexico, in that order of priority will receive capital. As I mentioned in my prepared remarks, we have built a very attractive cash position which we believe will allow us to execute on the development plans we have for the two -- primarily the two onshore assets, rather.

And I think while we are very proud of them, I'm not sure there are any other assets onshore that are any better than the DJ and the Delaware to be allocating capital to. So I think you should expect that we will look for opportunities, if they exist, for bolt-on acquisitions in both basins.

And I think you also should think through if we see opportunities in the Gulf as well to do something like we did last year. That was a very attractive deal. I think it was one that most people saw and understood as they got to know it a little bit better.

It's really the three Ds that will receive capital through cash flow, maybe incrementally with cash, potentially some acquisitions in and around things of those three. And then if we are wrong on oil prices, I think one of the things that we want to be a little bit mindful of is given the volatility of the oil markets is to keep a little dry powder and retain some flexibility if oil prices in fact move down in a way that today we don't anticipate.

So that's sort of the order of priority for the use of the cash. And the more asset sales questions, I think we're largely done. And we'll continue to think about the assets that we are going to feed capital to in a retention mode.

Evan Calio - ***Morgan Stanley - Analyst***

Great. Maybe a second question. Now that the Freeport transaction is closed, how should we think about the medium-term production profile in the GOM on this before any major new projects? Have many tie-backs potentially drilled in the 2017/2018 time period, and maybe even given Lucius is performing very well with the Fobus tie-back potential, how are you thinking about Lucius Phase 2?

Al Walker - ***Anadarko Petroleum Corporation - Chairman, President & CEO***

Darrell and I will tag-team your question. I think unfortunately a lot of the detail you're looking for there will be provided in March when we can combine them how we will allocate capital in 2017 relative to the expectations for what that's going to do for production growth. I will say whether it's the deepwater or it's the onshore, 2017 is a year in which were doing a lot of things to prepare ourselves for 2018 and 2019.

It's one thing as we come out of a trough, we just can't immediately turn on a dime and expect that we're going to go back to where we were before we went through the period of the last two years where industry in general spent a lot less capital and had a lot less activity. But maybe as it relates to the Gulf, I'll let Darrell address that specifically.

Darrell Hollek *- Anadarko Petroleum Corporation - EVP of Operations*

As far as the volume question we'll talk more about in March, but I think you can think take of it relatively flat over the next year or two, although we have opportunities to bring that up. You talk about Lucius. Lucius is continuing to perform above our expectations, and we are at 80,000 barrels a day today.

So we're in really good shape. We're basically full to nameplate, and we've got another well to be drill this year. We anticipate keeping that facility full, much like Caesar/Tonga is full, we'll probably drilling yet another well this year to make sure we'll keep it in that mode.

We have additional drilling and completions going on right now at both Heidelberg and K2, and they will add to our volumes this year. And I think what you'll see in March also, we'll touch more about it then, but when you look at the Freeport assets we're actually moving some of those opportunities in our drilling schedule today, and we really like the opportunities.

And so it will displace some other wells, but I think probably two-thirds of our rigs will be found on the development opportunities and probably about one-third of our rig time on exploration this coming year, with a lot of that focus on the things like Phobos, like Warrior, which is near our infrastructure. Again, looking at those as short-term turnarounds.

Evan Calio *- Morgan Stanley - Analyst*

Great. Appreciate it, guys.

Operator

Arun Jayaram, JPMorgan.

Arun Jayaram *- JPMorgan - Analyst*

Good morning. Just a quick follow-up, Al, to Evan's question. Given Anadarko's low core structure and development capabilities, you could argue there's a lot of earnings power sitting on your balance sheet with pro forma cash of more than $6 billion. So I wanted to get your thoughts on perhaps the urgency for APC to do some either bolt-ons or some corporate M&As. You think about 2017, the near view of the current valuations that you are seeing in terms of acreage values in the Delaware and the DJ.

Al Walker *- Anadarko Petroleum Corporation - Chairman, President & CEO*

Arun, it's a very understandable question when a Company's got as much cash as we do on a relative basis to our other assets. I think in the first half of the year in particular we're going to try to be as close to cash flow neutral with CapEx as we can.

I think we want to see a little more certainty in the oil markets, even though I have my own views and feel very strongly that we could in fact see an average price for WTI of $60 this year. I think with the expectation of where, if you just use the strip today and calculate what you think that's going to mean in the way of cash flow, I think initially we'll probably want to be more aligned with cash flow than we will be using excess cash.

But I think as we see that market develop and the direction I hope it's going to, I think our encouragement will correspondingly increase to where some of that cash could in fact be spent for additional drilling. And then I think where we see properties that give us the right synergies, whether it's operational or from a developmental perspective, the ability to maybe block up and do longer laterals and achieve better economics than we could by ourselves, those will be the things that will try to keep that dry powder for. I think as many people have seen in this basin, and if we could do some things that would improve our acreage footprint that might not necessarily require cash but maybe allow us to do some things creatively with blocking up, we would then in turn spend more capital on longer laterals and I think create better economics.

Arun Jayaram *- JPMorgan - Analyst*

Great. Thanks for that. My follow-up. Al, I understand what you're going to give us your plan to in early March, but wanted to know if you could give us or help us, just given all the A&D activity that you participated in, is what the anchor or baseline oil production number that we should be thinking about to anchor that 12% to 14% per annum growth over the next five years?

Al Walker *- Anadarko Petroleum Corporation - Chairman, President & CEO*

That's a really good creative question, but you're going to have to appreciate the fact that if I tell you that now you're not going to have anything to listen to in March.

Arun Jayaram *- JPMorgan - Analyst*

Okay. (Laughter). All right. Fair enough, Al. Thanks a lot.

Al Walker *- Anadarko Petroleum Corporation - Chairman, President & CEO*

Okay. Thank you.

Operator

Doug Leggate, BofA Merrill Lynch

Doug Leggate *- BofA Merrill Lynch - Analyst*

Thanks. Good morning, everybody. I wonder if I could take one high-level one-on-one detailed question, and hopefully we won't have to wait until March, we'll see.

At a high level, you made a comment I think in response to Evan's question about the go-forward portfolio. But there are still some fairly conspicuous assets. For example, Vito, which you previously sold and now you've got back again.

You emphasized Gulf of Mexico deepwater, but you didn't talk about international portfolio management. Could you just address, are you signaling that ex US generally, meaning ex Gulf of Mexico, the other parts of the asset base are not core? Because that would be new news, I guess.

Al Walker *- Anadarko Petroleum Corporation - Chairman, President & CEO*

No, I wouldn't take a quite that way, Doug, but I can appreciate why you are asking the question. The lion's share of what we will be talking about in March will be capital being allocated to the Delaware, the DJ and the Gulf of Mexico. I think long term we see those as the places we're going to invest capital.

Certainly in the short run if we try to stay closer to cash flow with CapEx, that's particularly important. It doesn't mean that other parts of the portfolio as you know it today will be starved or cannibalized. But I think as it relates to some other things, and let me just address you question on Vito, one of our partners there, [Preftice], Shell Preftice on Vito relative to the purchase price allocation. So that's what you don't hear us talking about that per se.

Other things in our portfolio as it relates to the Gulf of Mexico, I think Darrell and Danny Brown will be giving you more than sufficient color in March. But I think for as big a Company as we are, one of the things we very strongly that is our ability to give clarity around exactly the direction of where most of the capital will be spent in 2017, that it is short-cycle oil with very good wellhead margins. And I think as you can see from the results in 2016 we've done a very good job on the efficiency front in lowering the costs associated of delivering that revenue.

Doug Leggate *- BofA Merrill Lynch - Analyst*

I appreciate the answer, Al. My follow-up, and again hoping I might get some color here, is the Wolfcamp well that you announced. I want to really lever that into a question about your relationship with your partner there.

I don't want to be predictable about asking about M&A in that asset, but specifically what I'm really looking at is that the relative performance of your wells compared to your partner's wells appears to be -- there's a big gap, basically. What is your relationship like as it relates to the ending of this operating joint venture you have this year?

Will you continue to participate in daily FEs and vice-versa? And any color you give around what might have been different about what this one Wolfcamp well and whether it's repeatable? And I'll leave it there. Thanks.

Al Walker - ***Anadarko Petroleum Corporation - Chairman, President & CEO***

The one well is intended to be illustrative in terms of some of the things you see us doing there. I think we wanted you to have an appreciation for just what we thought was some of the real upside that maybe isn't always appreciated because we've not gone to development drilling yet in the Delaware. And that's really, as you well know Doug, from our experience in the DJ, that's when we really start to make things rock.

As it relates to Shall, we have a lot of confidence in them as a partner. They do a very good job. We have a good working relationship with them.

I think there's opportunities for both of us to figure out how to do things mutually better. And by that, I mean there may be some situations, and I alluded to just a minutes ago, there may be things where we can find opportunities to block up and acreage where it's a win/win for both of us, or some other things that frankly are not necessarily addressed in the joint venture but we'll still continue to be active with one another even after the joint venture expires midsummer.

I'm quite encouraged, frankly, by the relationship we have with Shell overall, as well as the conversations we have day to day on the operating of these assets. And it doesn't appear today to be a concern of mine, and I think as a Company, we operate a lot of places around the world where Shell -- we are an operator, they're an operator.

I think as a Company we have a very good relationship with one another, and when we have problems, we know how to get a hold of one another and talk about them. I think that's about the best way I can answer your question. I think we have a partner there which we have a very good working dialogue with, and that I think probably as commercial as we are in terms of understanding there may be some things that we can do different that would inure to the benefit of both of us.

Doug Leggate - ***BofA Merrill Lynch - Analyst***

I appreciate the answer, Al. Thank you.

Operator

Scott Hanold, RBC Capital Markets.

Scott Hanold - ***RBC Capital Markets - Analyst***

I'm going to hit on the, I guess, the large cash balance question again, a little bit differently though. If you could give some color on, when you look at your options. I mean, you guys have a lot of options with that balance at this point, but how do you think about your current leverage levels, your dividend, stock buyback as part of hierarchy for options with that cash balance going forward?

Bob Gwin - ***Anadarko Petroleum Corporation - EVP of Finance & CFO***

Scott, it's Bob. I think you should think in terms of us keeping, as Al said, the powder dry, keeping the cash for opportunities, be it increase drilling, bolt-ons, et cetera. I think returning cash to shareholders, either through buybacks or dividends, would be lower on the list, given our opportunity set is so significant that -- at current commodity prices.

It doesn't mean that we just completely say that's never going to happen. Obviously we'll make those decisions at points in time in the future. But a year ago, I think, the general view of our balance sheet and our opportunity set was that we didn't have much flexibility.

Over the last 12 months, that's markedly different. And now I think a lot of folks see that cash balance and say it's quite high. It is on a pro forma basis high, but the flexibility and the potential for future opportunities drives that cash balance and our desire to maintain that flexibility in 2017 rather than to even go down the path of thinking about returning that cash to shareholders. We think we could do a lot with that cash for shareholders, and that's a better path forward.

Scott Hanold *- RBC Capital Markets - Analyst*

Understood. Thanks for that. As a follow-up question, a little bit on the Delaware and the DJ in terms of some of the production trajectories into the fourth quarter, a little bit more flat then in, say, prior quarters and with your ramp-up activity. Could you give a little color on what that looked like in 4Q and (technical difficulties) of 1Q, was there a little bit of a lag in some of the numbers there?

Darrell Hollek *- Anadarko Petroleum Corporation - EVP of Operations*

Scott, this is Darrell. I think Wattenberg, if you look at the numbers, yes, our oil was down, our volumes were setting records. So when you look at the third quarter going into the fourth quarter, and a lot of that upside has to do with gas since we were -- when we pull back earlier in the year as hard as we did we were sort of focused on the base, and the guys did a fantastic job keeping volumes and getting volumes up. And we will still coming off the backs of a bigger drilling program in 2015.

But if you recall, we spent more than half the year with one rig in the field. That took it's toll. When you look at what we did there in the fourth quarter getting ready for 2017, we basically went from one to five rigs in the fourth quarter.

So I think expectation going forward is you will see us turning a lot more new wells back on and so you will see that oil percent again come up. When you look at Delaware, we also sort of ramped those rigs from six to nine leaving the fourth quarter, and continue ramp them today. I think we have 11 rigs today and looking to go up a few more yet this quarter.

You can expect that we will continue to see rates increase in Delaware. But just remember, the cycle time to drill complete and tie things in are roughly going to be six months, plus or minus, depending on where we are.

Scott Hanold *- RBC Capital Markets - Analyst*

Understood. Appreciate that. Thanks, guys.

Al Walker *- Anadarko Petroleum Corporation - Chairman, President & CEO*

Thank you.

Operator

Ed Westlake, Credit Suisse.

Ed Westlake *- Credit Suisse - Analyst*

Good morning. Clearly a lot of excitement about the Delaware and the exciting well, still relatively small for you today. Could you just maybe talk about the key infrastructure items which will allow you to deliver the growth and timing? I know on the third quarter call you said in 2017 you didn't see much issue, but just a bit of a roadmap would help.

Al Walker *- Anadarko Petroleum Corporation - Chairman, President & CEO*

Let me start by saying I will have Scott Moore who runs the Marketing for us Globally address some of the takeaway questions, as that clearly is an issue that we address through the midstream organization as well as to our marketing. I think you've seen us invest heavily through the years in midstream to the point where we try to philosophically deliver an upstream result with a midstream solution.

And that has kept us from not sitting there for days on end waiting for pipeline connection. And that's a really hard thing to do, given the activity level in a basin like the Delaware.

I think Darrell and Don Sinclair have done an extraordinarily exceptional job with making that midstream spend be in sync with the upstream spend. But as it relates to I think specifically your question on takeaway and debottlenecking, and how do we move hydrocarbons out of that particular basin, let me have Scott address that.

Ed Westlake - ***Credit Suisse - Analyst***

Think you.

Scott Moore - ***Anadarko Petroleum Corporation - VP of Worldwide Marketing***

One of the things we focus obviously very close on is making sure that the takeaway capacity meets the growth profile. In this Delaware basin, that's probably the hottest topic on people's minds.

I think it's important to realize in the big picture there's about, in West Texas, there's about 2.6 million barrels a day pipe capacity and refining demand and production running 2.2 million barrels. And we track about 1 million barrels a day of new projects that are in various phases of development from the pipeline developers, and I think they're doing a nice job of anticipating growth in the industry.

And we are very involved in those discussions. And so I think there's a nice balance going on between the producers' growth profiles and what the infrastructure developers are doing on the crude oil side of things.

In gas and NGLs, those facilities, those pipes run about two-thirds full. And I would say from the same story, that the overall matching of takeaway capacity and producer growth profiles is reasonably well choreographed. It's not perfect, but we're generally comfortable with that.

Darrell Hollek - ***Anadarko Petroleum Corporation - EVP of Operations***

I may add just a little bit here from a midstream perspective. One of the benefits we have is that we do have that midstream component. And as we talk about ramping up Delaware and DJ, and DJ is a little bit different because -- since we have so much infrastructure in place. But our asset teams are working very closely with midstream to make sure they understand where we're moving.

And as we are testing such a big acreage position, it's not always easy for our midstream but the fact that they are in sync with what were trying to accomplish helps tremendously. But you'll see, just like we are ramping up our rig activity, you'll see us ramping up the midstream components.

So they'll be a big spend here the next two years, just making sure we have the infrastructure in front of us.

Ed Westlake - ***Credit Suisse - Analyst***

It does feel to me when I look at some of the wells that there may be infrastructure constraints in terms of how you can produce, particularly, say, maybe on gas processing, as you've alluded to a little bit in terms of appraisal mode. But as you get certain bits of kit in the field that there could be some sort almost step changes in production as we look at through 2017 and 2018.

Al Walker - ***Anadarko Petroleum Corporation - Chairman, President & CEO***

Ed, I think you're seeing it accurately. And I think the one thing, without sounding braggadocious, is that we have for a long time taken the view that midstream is the solution for an upstream success and not trying to third party an association with someone to do that for us. Being able to control our own midstream and takeaway capacity, whether it was in the DJ and now the Delaware, I think is part of the recipe for why we've been successful and we're [a lot] likely to have the same bottlenecking issues that have potential for putting a lot of hydrocarbons on the side until markets open up.

I've been very pleased with the work that Darrell and Don have done that Darrell just alluded to, but also making sure that, through our marketing organization, that we are moving this at the best price we possibly can. And I do think, again without sounding overly braggadocious, that is a differentiating factor for us.

Ed Westlake - ***Credit Suisse - Analyst***

Thank you.

Operator

Brian Singer, Goldman Sachs.

Brian Singer - ***Goldman Sachs - Analyst***

Thank you. Good morning. Al, six months ago you outlined your expectations for a sustained $60 oil in 2017 and your willingness to commit to ramp activity ahead of that to benefit more quickly. And I believe you referenced $60 again here this morning, and wanted to just see, A, if the rig count exits for the first quarter that you've already committed to gets you to the run rate that you think is reasonable and consistent for that $60 environment? And then, B, if you'd give us an update on cost inflation, any milestones you're looking for as you think about the second half of this year and into 2018 that would make you further or lower your activity levels?

Al Walker - ***Anadarko Petroleum Corporation - Chairman, President & CEO***

Okay. Understandable question, and I appreciate you asking it. I think when you go back to the second quarter, at that time it wasn't just me, I'll say we as an organization, were thinking that demand would likely at some point absorb the shortfall we were seeing at that point with the oversupply. And that the oversupply in fact would come into equilibrium during 2017 and produce what I thought would be an average price of $60.

Now, I'm not going to begin to tell you that we saw the supply activities from OPEC as a likely scenario. I think we all were watching that with the same skepticism as to whether or not OPEC would do it, and then in fact with the non-OPEC nations that have further taken supply off the market helped.

Whether you're looking at EIA or IEA data, most people think that the market's going to expand by 1.5 million barrels per day on the demand relative to the way in which we are now supplying the market. It doesn't sound or feel like to me that we're likely to get into an oversupply situation through 2017. The only thing that I would say that's a little surprising to me would've been that, if you recall, I thought domestic oil production in the US would probably bounce off 8 million barrels a day, and we actually bounced a little higher than that.

But I think if I use our own Company as a bit of an analogy for this comment, I don't think even with the rigs that we're all starting to stand up, particularly in the Permian, and if you look even at what Exxon Mobil has said about it this week, you couple that together and it's not like in 2017 you going to see a tremendous supply response that will dwarf the improving demand. I think that's really more something to look at in 2018 and 2019. It's a little fuzzier when you look into the crystal ball at that point.

But I do, Brian, believe that the improvement in the demand function coupled with the now market that we're into for supply should give us the encouragement for the type of oil price I've been making reference to since last year. And that's why we did the things we did in the second half of 2016 to get ready for 2017, and that's why in March you'll hear a capital plan that not only provides a follow-through on that, but really gets us ready for what we believe will be the real volume improvements that are ahead of us in 2018, 2019 and beyond.

Brian Singer - ***Goldman Sachs - Analyst***

Thanks. And so part of the question which maybe is a March one, was whether the run rate that you've committed to already for the end of the first quarter is consistent with that $60 environment, or whether there'd be additional increases that should be coming?

Al Walker - ***Anadarko Petroleum Corporation - Chairman, President & CEO***

I thought I did a good job by not answering the question, Brian. (Laughter). You caught me.

In all seriousness, no. If we saw a $60 sustained environment, you should suspect that we would stand up more rigs because the capital plan that we have currently under consideration for hopefully approval by our Board later this month is really predicated on a much lower oil price then $60. If you think back what I said earlier about the fact that were going to, at least for the first half of the year, try to sync up cash flow with CapEx, if we see an approving oil price that gives us that sustained $60 average with some comfort, that would imply if you just do the math that we think higher oil prices in the second half of the year are more likely since were not at $60 today.

If you fast forward to this year's second quarter conference call, I bet we have another conversation about this. And hopefully it will be where oil is at $60 and we're now talking to you abut adding more rigs to what we anticipate would be our drilling program for the full year.

Brian Singer - ***Goldman Sachs - Analyst***

Okay. Thanks, Al. And then any update on Mozambique in terms of timing key milestones and then on the strategic importance and any potential for asset sales?

Al Walker - ***Anadarko Petroleum Corporation - Chairman, President & CEO***

Okay. Let me address that with Mitch. Did you ask me about asset sales as it relates to Mozambique or asset sales in general, just to clarify the question?

Brian Singer - ***Goldman Sachs - Analyst***

Mozambique specifically, only because we get the question and I figured we could go right to the source.

Al Walker - ***Anadarko Petroleum Corporation - Chairman, President & CEO***

Why don't I address that, and then I'll ask Mitch if he would address the other parts of it since he does the hand-to-hand combat every day on those questions. We aren't currently looking at Mozambique as a sale candidate as an asset.

I think there's a couple of reasons that probably are intuitive, but nonetheless worth pointing out. One is, I don't think we would get a lot of value in the asset prior to taking FID. It's not to say that somebody might not step up with an offer that would be surprising to us.

We are in discussions with absolutely no one today on that front. And it's always been our view that until we get the FID and we get all the variables that Mitch is going to talk to you about better understood if not completed, I'm not sure why we would be motivated pre-FID. And then post FID on our way to a first lifting, it's an asset like any other asset in our portfolio. If somebody thinks more of it than we do, we're ready to sell it.

And I think we've done that enough times with our approach to portfolio management, we would do it again. But I think in the short run today, and Mitch is going to walk you through some of these milestones and some of the positive developments that we are having, for people to be thinking about Mozambique as being a sale candidate is just very unlikely.

And I don't think if it even were to occur and the vacuum of sort of a philosophical conversation, it wouldn't be at a price point that would make a lot of sense because again, all of the risk associated with getting from here to FID would be factored into someone's offer. And so therefore we are much more comfortable as a hold asset today. And then we'll approach whether it's a hold asset after we take FID.

Mitch Ingram - ***Anadarko Petroleum Corporation - EVP of Global LNG***

Brian, I'll just give you an update on where we are with regards to the key milestones. We've made good progress in the last quarter working with the government where our immediate priority is to conclude all of the outstanding agreements, known as legal and contracted framework, and we hope to have the key agreements concluded in the very near future. What that does is allow us then to put our key buyers and strategic buyers in Asia, who are now seeing that the project is going to proceed.

And the key event for them was getting these legal protection frameworks concluded. And we're progressing those agreements from our hedged agreement into sales and purchasing agreements. As we've indicated in the office report, we've gained approval for reassessment plan, and we continue to discuss with the government some outstanding associated agreements. And those allow us then to proceed with [reassessment] when all of the legal and contractual framework has been completed. And parallel activities for this include us securing project financing to fund approximately two-thirds of the project capital going forward, and those discussions are ongoing and will continue throughout this year.

In addition to that, we continue to look at construction and installation activities, and really look at optimizing cost opportunities within the project and really derisking the execution phase of the project. So all of these key activities being legal and contractual framework, including our offtake agreements, finalizing our project financing, and we optimizing how we execute the project will take us to the point of FID. So we'll continue to update you as we progress through the year.

Al Walker - ***Anadarko Petroleum Corporation - Chairman, President & CEO***

Brian, let me add, we will you, as you would expect us to, go into significantly more detail in March about all of the things Mitch made quick reference to, as well as what we see is a very minimal capital commitment to advancing each of these things because at this point were still not into a very capital intensive portion of it. So it's really building the option value that I made reference to through between here and FID.

Brian Singer - ***Goldman Sachs - Analyst***

Thank you very much.

Operator

Charles Meade, Johnson Rice.

Charles Meade - ***Johnson Rice & Company - Analyst***

Good morning, Al, and to the rest of your team there. If I could go back to the comment you made earlier on, CapEx and capital balance first half 2017. That's helpful insight into how you're at least beginning to approach the year.

One of the question that we bat around over here a lot is, how much you might want to outspend your cash flow, outspend CapEx over cash flow? And then how much you could before you would start to perhaps lose efficiencies on productivity or efficiency, that sort of thing? Can you talk about what would be the factors that would whet your appetite to outspend cash flow, and what operational constraints do you have your eye on that might prove to be limiters as you -- if you choose to accelerate?

Al Walker - ***Anadarko Petroleum Corporation - Chairman, President & CEO***

Well, as I know you expect, I'm going to say a lot of the question you're asking we will cover in March. That said, we've announced that we will be moving a considerable number of people to Midland, a little over 200 folks that will be actively involved in the development of a very large oil resource.

We believe that was the best way to execute the development of the field, keeping in mind we're still sort of by and large in the appraisal portion. So as Brad Holly and his organization begins to move into a full development of our acreage, it's really at that point I can say more in a philosophical way, that we would be encouraged to outspend cash flow with CapEx if we saw, A, value in that process, and B, it created a value proposition with growth that we believe would be not only beneficial to the Company but to the folks that would invest in the Company.

Today were not quite into that development portion or stage, we're preparing for it. We believe we'll have ourselves in position through the course of this year to be able to execute on that, if in fact we have a commodity environment that's favorable. And we believe we have in place the people, the human resource component, to be able to deploy the capital resources.

I think as you've heard us talk about today, and Bob and his folks have done just an almost magician's like effort through the course of 2016 getting the balance sheet in a better spot, preparing ourselves with cash for flexibility to do lots of different things. Once we find ourselves in a commodity environment that encourages

development, I think that is when you will see us be more philosophical in our views towards wanting to put more capital into the play then we will during the appraisal portion. But probably should stop there, otherwise you're not going to have anything to listen to in March around what is easily the most exciting asset we have today in our portfolio.

Charles Meade *- Johnson Rice & Company - Analyst*

Al, that was definitely a helpful philosophical disclosure not a dodge at all. The second question I had, if I could just get you guys to give us a little color or whatever you like to add on what's going on offshore Colombia. It looks like versus what you guys were talking earlier in 2016, you got on that well a little earlier. And I'll just ask for the update there and what we should look for in the next few months.

Ernie Leyendecker *- Anadarko Petroleum Corporation - EVP of International and Deepwater Exploration*

Yes, Charles. Hi, this is Ernie. The well that we're on right now, Purple Angel, is on plan. Effectively we spudded some time in December, and we've got operations that are still ongoing now, so we're not quite ready to talk much about it.

But I expect and hope that by the time we get to our March investor analyst day that we'll be a little bit of news to talk about. We are testing effectively the Kronos discovery in this Purple Angel location right now, and when we're done we're go up north and test another analogous structure to the feature we're on right now called Gorgon. So really a lot more to come in the context of the Grand Forte area gas frontier in the future, so we'll leave that for March.

On the other front in the ultra deepwater area we have where we shot the 30,000 square kilometers, we're working on the early processing of that. We've obviously pretty encouraged about what we are seeing. We'll get the final processing done by the end of this year, and we're really starting to think about planning and have identified some ideas to test hopefully in 2018. And we're starting the pre-drilling prep work in terms of permitting and environmental impact assessment and the requirements to get ready to do that, as well as the drilling rig requirements that we are starting to test wells in this pretty deep water out there in the Grand Col area. So that's where we are in Colombia today.

Charles Meade *- Johnson Rice & Company - Analyst*

Thanks for that detail, Ernie.

Operator

Bob Brackett, Bernstein.

Bob Brackett *- Sanford C. Bernstein & Co. - Analyst*

Could you talk about the Shenandoah semi-sub concept, and give us some idea of maybe how you chose that concept, the scale of that facility and the steps moving toward FID?

Al Walker *- Anadarko Petroleum Corporation - Chairman, President & CEO*

You bet. Keep in mind that is what of one that's in both Ernie's shop and in Darrell's shop. So it sort of -- it's neither fish nor fowl, so we're going to hand that in two parts here. Let me have Ernie just speak a little bit about where we are geologically with our understanding of the asset, or the opportunity of the asset. And then Darrell'll answer the question about the production solution.

Ernie Leyendecker *- Anadarko Petroleum Corporation - EVP of International and Deepwater Exploration*

Last year we drilled the number five well where we found yet over 1,000 feet of hay, and we have moved onto the sixth appraisal well. We're taking a measured approach to continue to delineate the resources, in particular on the east side of the structure as we drilled through -- past the number two, three and four wells and

learned about a little bit of the complexities, structural complexities on the feature, we felt we needed some more comfort around the resource in place towards the east, as well as trying to penetrate the physical oil-water contacts.

So the number six well we're drilling today is designed really to test part of the eastern side of the field for reservoir continuity, as well as cut some oil-water contacts, which we haven't physically done yet. We're hopeful, of course, that the well will penetrate those. I can also share with you that the well is designed ultimately to be kept as a keeper, and potentially be a producible well ultimately one day when we see ourselves as a final solution for the field.

Darrell Hollek - ***Anadarko Petroleum Corporation - EVP of Operations***

Bob, this is Darrell. As you're aware, we were looking at both semi-sub and SPAR. We've got both of those in our fleets today, so were very familiar with both of them. It just came to a point rather than spend the time and energy to do feeds on both of those structures, we saw the flexibility in the semi-sub, not only for taking on what we think we may have there, Shenandoah, but understand that we have a lot of prospectivity in the area itself.

And so as you look at long term trying to build a hub in the area, we just felt from a payload standpoint the semi-sub gave us a lot more flexibility. So as we move forward here trying to understand our path to sanction, we're just trying to understand how we would handle the semi-sub, but were clearly in the camp that's what it will be if we get to FID.

Bob Brackett - ***Sanford C. Bernstein & Co. - Analyst***

If I interpret that little, a standard 80,000 barrels spar wasn't big enough to handle the volumes you expect to come off Shenandoah?

Darrell Hollek - ***Anadarko Petroleum Corporation - EVP of Operations***

I would say it doesn't give us the flexibility for the entire area. We're still learning my Shenandoah itself, so that in itself we want that flexibility. But when you look at the entire area and the prospectivity and the leases that we actually have today, we want to make sure we have the flexibility to grow that facility, if need be.

Bob Brackett - ***Sanford C. Bernstein & Co. - Analyst***

And on that 1,000 foot of oil, do you think that's all in pressure communication and there's a single oil-water contact? And what do you think about the energy or the drive on that oil-water contacts?

Darrell Hollek - ***Anadarko Petroleum Corporation - EVP of Operations***

Actually you may recall, there are multiple Wilcox reservoirs in that discovery solution. Each every one of them may have a separate oil-water contact, and they are not likely connected vertically. So we're treating them independently, and we've got to really understand each and every one of the reservoir flow units there.

Al Walker - ***Anadarko Petroleum Corporation - Chairman, President & CEO***

I think, Bob, Al here. In closing I think until we find the oil-water contact here, either in this next well or, frankly, even if we need to one thereafter, our ability to understand the fluid dynamics will be significantly better than they are today.

Bob Brackett - ***Sanford C. Bernstein & Co. - Analyst***

Thank you.

Al Walker - ***Anadarko Petroleum Corporation - Chairman, President & CEO***

You bet.

Operator

John Herrlin, Societe Generale.

John Herrlin - ***Societe Generale - Analyst***

I won't try to front the March meeting, but I'll ask a spending question anyway. Given your balance sheet capacity, you have a lot more flexibility than you did last year.

Should we expect during 2017 or 2018 that you increase your long-cycle exposure versus your short-cycle activity? That's question one. And then question two is on the Freeport properties, do you think you have as much subsea tie-back potential as what you've indicated on the traditional Anadarko deepwater Gulf of Mexico facilities?

Al Walker - ***Anadarko Petroleum Corporation - Chairman, President & CEO***

John, to answer the cycle question, to start with that one, I cannot anticipate today that the application of some of the cash as you will see it billed to the course of this year would be disproportionate in a sense that's -- I think the mix, to answer I guess that way, would be consistent with the capital plan we roll out in March. So I don't think you should expect that capital allocation would change as we think about how to deploy that cash. It will be still largely short-cycle.

I don't think today we are limiting Ernie or Mitch with the long-cycle things that they have as option value in our portfolio with capital. So it's really not a need to reallocate that capital into the longer-cycle things that either Mitch or Ernie are working on.

And I think you should expect that the mix that we talk about in March would be the same mix as we roll forward. Where we to deploy some of that cash, and in fact would say the cash would initially go most like to the Delaware first, DJ second and the deepwater Gulf of Mexico third.

Now on the subsea tie-backs, I'll let Darrell address that. But in general we've been very pleased with the subsea tie-back opportunities we've seen since we've taken over the Freeport properties.

Darrell Hollek - ***Anadarko Petroleum Corporation - EVP of Operations***

John, as far as what they have in inventory, we're just now getting our arms around it. But we understood that they had opportunities. As we look at them today, I would say there's at least a dozen to maybe 20 of those development opportunities that I think can compete in our portfolio.

I think what it doesn't speak to is some of the expiration opportunities we've picked up near that same infrastructure. So I would say they're in excess of that. It doesn't double our existing portfolio, but I tell you, it adds a lot of depth to the portfolio we have for future tie-backs. We feel really good about it.

If I go back to Al's point on capital, the only thing I'd remind you of, if you think of last year, we pulled back hard when prices went down, and most of that pullback was in onshore. And so as you look at what we're doing right now in ramping up, I think you'll see probably a lot of money going back into onshore now, because we are somewhat limited in deepwater with the rig fleet we have.

John Herrlin - ***Societe Generale - Analyst***

Great. Thank you.

Operator

David Heikkinen, Heikkinen Energy Advisors.

David Heikkinen - ***Heikkinen Energy Advisors - Analyst***

Good morning, and thanks for taking my question. Al, I'm hoping to elicit some of your thoughts on the trajectory of operating expenses into 2017 that really follow on the accomplishments you highlighted in 2016. Can you just talk about as you focus on the three Ds what happens on the cost side?

Al Walker *- Anadarko Petroleum Corporation - Chairman, President & CEO*

Well, I think like many, we anticipate that as industry increases the number of rigs in the Permian that the completion costs there will certainly be under pressure. I think both of the primary, or two of the largest service companies have already come out with their own thoughts about what that might look like.

We know from just a cost of service being provided it's likely to go up. So were not arguing that one. I think what we'll continue to do is some of the things that I'll ask Darrell to speak to a little bit, because I think we're all pretty proud of the efficiency gains that were achieved, and really the lower cost that I made reference to in my prepared remarks of less than $3 per BOE, those were not from anything more than efficiency gains and increased volumes in order to get that unit cost down.

So it's really, it's speaking to the leverage that we've been able to create off of the fixed costs and the limited pressure we had in 2016 on the variable costs. Obviously in 2017 and 2018 the variable costs are going to go up. And Darrell, maybe with that as an intro, you can talk a little bit about some of things that we're seeing on the pressure on prices with some of the services that we're now dealing with since everybody knows they're going to go up.

Darrell Hollek *- Anadarko Petroleum Corporation - EVP of Operations*

Let's start with the capital side. I think by far there will be pressure, we understand that. We were very fortunate to have the service sector work with us as close as they did when things were declining as fast as they were on the commodity cycle.

It's clear that they're going to have to get a better margin so that they too stay in business. So we expect that to go up. We're working very closely with our providers right now so that we can sort of minimize that to the extent we can, but the pressure is going to be there.

I think from an LOE standpoint there's a lot of things that really happened in our favor in 2016, in that again we talked about the additional production because we focus on that base. So we end up with some volumes on a BOE basis that didn't necessarily expect, but we also had, again, a lot of reductions, and whether it be personnel costs, chemical costs, you name it, we had the advantage of that.

And in some cases early in the year when prices were down below $30, we didn't do the work-overs and things that we may traditionally have done because the economics weren't there. And so I think as you look into 2017, we may not be hold onto that. And I think the thing you've got to remember, too, is that as we move to oil there'll be pressure on that LOE as well. But with that comes a much higher margin.

So I think the guys did a fantastic job this year. To Al's point, a lot of that we'll be able to hold onto, but there'll be some pressure on the LOE number as we move forward.

Al Walker *- Anadarko Petroleum Corporation - Chairman, President & CEO*

David, just to reiterate the obvious, particularly for someone like yourself because I know you know this but I'm make a point anyway. As we move in the Delaware from appraisal to development, Brad will drive down the cost to drill the wells and operate the wells as we move into that pad development mode. And so we do still have a lot of efficiency gains in front of us, even fighting the headwind of higher service costs.

David Heikkinen *- Heikkinen Energy Advisors - Analyst*

Al, I'm trying to think this a little sensitive question, but I know that when I was an engineer I wanted to be close to where money was being spent, but then I also put myself in the place of not wanting to live in Midland, Texas. So as you move from the Woodlands to Denver, how is the organization really coalescing around the new structure?

Al Walker *- Anadarko Petroleum Corporation - Chairman, President & CEO*

Well, I think for those engineers and those petro professionals that want to be a part of one of the largest oil discoveries in the world and be a part of the development associated with what we see in a Delaware, professionally it's an incredible opportunity. I think Midland and Denver has places where we think of ourselves of having regional offices to be able to better develop the DJ outside of Denver and the Delaware outside of Midland is the right way for us to think about running the railroad.

And I think the professional challenges and the opportunities associated with being able to be a part of probably one of the largest greenfield developments that are likely to be seen in the careers of most engineers and other petro professionals, living in Midland is a secondary issue. And I think we found that many people have discovered the fact that Midland is a pretty good place to be, At least all of my friends that have lived out there all of lives certainly think that's the case.

They're not too excited about their small city getting a lot larger. If you lived in Midland, which I haven't, but I have a lot of friends out there, it's a pretty good place to call home. Yes, it's the Woodlands? No. It's got its own advantages and disadvantages, but if you just think about it from a professional opportunity, it is unique. And one that very few people in their career get to be a part of, whether there an engineer in the midstream organization or in the upstream organization, or they're in the growth organization that Shandell Szabo now runs. As we look for other opportunities in and around that, having a presence in Midland, being a part of the Midland community will be as much of a recipe of success as having a Denver regional presence as it was as we developed the DJ.

David Heikkinen - ***Heikkinen Energy Advisors - Analyst***

That make that make sense, and the operators in the Midland have done a lot to improve the quality of life, as we visited their offices. So thanks for that.

Al Walker - ***Anadarko Petroleum Corporation - Chairman, President & CEO***

You bet.

Operator

Ryan Todd, Deutsche Bank.

Ryan Todd - ***Deutsche Bank - Analyst***

Maybe one follow-up on the Permian first. Can you talk a little bit, you had mentioned various times the shift from delineation to development at some point. Can you talk about what are the key things you're still trying to figure out on the appraisal side?

And kind of key steps to allow you to move toward a full development? And what are you still testing over the course of 2017, both in and outside of the Wolfcamp?

Al Walker - ***Anadarko Petroleum Corporation - Chairman, President & CEO***

I think one of the things you can understand and appreciate about where we are currently in the appraisal portion of this play development is that we are aggressively drilling where we can in order to achieve operatorship. We believe as an operator we will be able to do a lot of things that inure to the benefit of our Company over time.

As operator, we understand how we will want to pace that development and that drilling activity and completion activity, and be able to sync it up with our midstream spend. At the same time, as Brad and those that work for Darrell that are day to day in this asset, we continue to have a better understanding of the rock properties that we are dealing with during this appraisal portion so that when Brad is prepared to move into full development, we know how to best optimize the development and the completion techniques associated with those rocks.

I don't think it's any more complicated than that, but I think those that have worked the Delaware will tell you the Wolfcamp is an incredible rock. And it's giving us opportunities, frankly, we've not seen in very many places in North America. And it gives us a lot of understanding, but having said that, we are still trying to best understand how we would in fact go into a full development mode. And Darrell, you might talk just a little bit about that.

Darrell Hollek - ***Anadarko Petroleum Corporation - EVP of Operations***

I think Al summed it up well. I think that the thing that's unique about us is the extensive position we have, and it varies across that position, is what we are finding. It's all very encouraging, but before we go in that development mode we really want to have a good handle on it.

It also helps us understand how we want to position our midstream. The fact that we're able to have more activity today than maybe we were looking at two or three quarters ago is helpful in terms of the trying to get us in that development mode.

It's our hope that by the end of this year we should hopefully start moving down that path and we should see a lot of synergies. We're trying to get there as quick as we can.

Obviously the Wolfcamp A is probably the biggest target for us, but there's still a lot of opportunity inside the Wolfcamp B and the Bone Springs, as we see it, not to mention the Avalon and certain parts of this field. So just a lot of opportunities here to make sure we understand it before we get in that development mode. But I tell you, I'm encouraged that we'll get there sooner than later at the pace we're going at right now.

Ryan Todd - ***Deutsche Bank - Analyst***

That's great. Are we going to see some Bone Spring wells over the course of 2017?

Darrell Hollek - ***Anadarko Petroleum Corporation - EVP of Operations***

I think you're liable to see a couple. We're still focused largely on the Wolfcamp at this point, being the deeper horizon.

Ryan Todd - ***Deutsche Bank - Analyst***

Great. Maybe one last one. I think you touched on this briefly earlier on, but I wasn't sure if I missed the comments, or if you really said much. In terms of cost inflation, can you talk a little bit about what you expect over the course of 2017 and what you're seeing so far?

Al Walker - ***Anadarko Petroleum Corporation - Chairman, President & CEO***

Well, you're right. I didn't address that specifically because I think it relates to vendor conversations and negotiations. If you are dealing it on a well-to-well basis, yes, it's going to go up significantly.

If you looking at it like we do where we're maybe looking at multi-year contractual arrangements, you may not have quite as -- I won't say, you're [won't] have the similar conversation with the service provider, and I think our inclination is to go into a longer contractual period to be able to do something that's a win/win for both of us rather than going well to well. I hope that addresses your question as best as I'm going to try to answer it today.

Ryan Todd - ***Deutsche Bank - Analyst***

Okay. Thank you

Al Walker - ***Anadarko Petroleum Corporation - Chairman, President & CEO***

If I could, it's the top of the hour. I know there's other things going on today. I do want to close by saying one more time how much I appreciate what our employees did in 2016.

I think Anadarko, like many other companies, benefited by having a culture that really allowed us to get through an extraordinarily difficult period over the 1.5 years to 2 years. And 2016 seemed to be the absolute bottom of the cycle in many, many ways.

When I think about where our Company was a year ago and where we have it today, it's just nothing can be said short of just thanking the employees for all the hard work, long hours and courageous activities that were undertaken in order to get where we are. To each of them, thank you.

And to those of you still on the phone and those of you that are listening in by recording, we look forward to seeing -- or talking to each of you, rather, in March. As always, don't hesitate to give Robin a call if you have any questions. Thank you.

Operator

Thank you, sir. Today's conference has now concluded, and we thank you all for attending today's presentation. You may now disconnect your lines, and have a wonderful day.

Exhibit 117

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2016

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File No. 1-8968

ANADARKO PETROLEUM CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	**76-0146568**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1201 Lake Robbins Drive, The Woodlands, Texas	**77380-1046**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code **(832) 636-1000**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.10 per share	New York Stock Exchange
7.50% Tangible Equity Units	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

The aggregate market value of the Company's common stock held by non-affiliates of the registrant on June 30, 2016, was $27.3 billion based on the closing price as reported on the New York Stock Exchange.

The number of shares outstanding of the Company's common stock at February 3, 2017, is shown below:

Title of Class	Number of Shares Outstanding
Common Stock, par value $0.10 per share	558,979,551

Documents Incorporated By Reference

Portions of the Definitive Proxy Statement for the Annual Meeting of Stockholders of Anadarko Petroleum Corporation to be held May 10, 2017 (to be filed with the Securities and Exchange Commission prior to March 31, 2017), are incorporated by reference into Part III of this Form 10-K.

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COMMONLY USED TERMS AND DEFINITIONS

Unless the context otherwise requires, the terms "Anadarko" and "Company" refer to Anadarko Petroleum Corporation and its consolidated subsidiaries. In addition, the following company or industry-specific terms and abbreviations are used throughout this report:

364-Day Facility - Anadarko's $2.0 billion 364-day senior unsecured revolving credit facility maturing in January 2018

3D - Three-dimensional

$5.0 Billion Facility - Anadarko's $5.0 billion senior secured revolving credit facility, which was replaced in January 2015 with the Five-Year Facility and a 364-day facility

AROs - Asset retirement obligations

ASU - Accounting Standards Update

Bbl - Barrel

Bcf - Billion cubic feet

Bcf/d - Billion cubic feet per day

BOE - Barrels of oil equivalent

CGF(s) - Central gathering facility(ies)

COSF - Centralized oil stabilization facility

DBJV - Delaware Basin JV Gathering LLC

DBM - Delaware Basin Midstream, LLC

DD&A - Depreciation, depletion, and amortization

EOR - Enhanced oil recovery

EPA - U.S. Environmental Protection Agency

Fitch - Fitch Ratings

Five-Year Facility - Anadarko's $3.0 billion five-year senior unsecured revolving credit facility maturing in January 2021

FPSO - Floating production, storage, and offloading unit

G&A - General and administrative expenses

GAAP - U.S. Generally Accepted Accounting Principles

GOM Acquisition - Acquisition of oil and natural-gas assets in the Gulf of Mexico, which closed on December 15, 2016

GPM - Gallons per Mcf

IPO - Initial public offering

km^2 - Square kilometers

LIBOR - London Interbank Offered Rate

LNG - Liquefied natural gas

MBbls/d - Thousand barrels per day

MBOE/d - Thousand barrels of oil equivalent per day

Mcf - Thousand cubic feet

MMBbls - Million barrels

MMBOE - Million barrels of oil equivalent

MMBtu - Million British thermal units

MMBtu/d - Million British thermal units per day

MMcf/d - Million cubic feet per day

Moody's - Moody's Investors Service
NGLs - Natural gas liquids
NYMEX - New York Mercantile Exchange
Oil - Includes crude oil and condensate
OPEC - Organization of the Petroleum Exporting Countries
PUDs - Proved undeveloped reserves
SEC - U.S. Securities and Exchange Commission
S&P - Standard and Poor's
Sonatrach - The national oil and gas company of Algeria
Tcf - Trillion cubic feet
TEN - Tweneboa/Enyenra/Ntomme
TEU or TEUs - Tangible equity units
Tronox - Tronox Incorporated
TSR - Total shareholder return
UOP - Unit-of-production
VIE - Variable interest entity
WES - Western Gas Partners, LP, a limited partnership and publicly-traded consolidated subsidiary of Anadarko
WES RCF - WES's $1.2 billion five-year senior unsecured revolving credit facility maturing in February 2020
WGEH - Western Gas Equity Holdings, LLC, the general partner of WGP
WGH - Western Gas Holdings, LLC, the general partner of WES
WGP - Western Gas Equity Partners, LP, a limited partnership and publicly-traded consolidated subsidiary of Anadarko
WGP RCF - WGP's $250 million three-year senior secured revolving credit facility maturing in March 2019
Zero Coupons - Anadarko's Zero-Coupon Senior Notes due 2036

PART I

Items 1 and 2. Business and Properties

GENERAL

Anadarko Petroleum Corporation is among the world's largest independent exploration and production companies, with approximately 1.7 billion BOE of proved reserves at December 31, 2016. Anadarko's mission is to deliver a competitive and sustainable rate of return to shareholders by developing, acquiring, and exploring for oil and natural-gas resources vital to the world's health and welfare. Anadarko's asset portfolio is aimed at delivering long-term value to stakeholders by combining a large inventory of development opportunities in the U.S. onshore and the Gulf of Mexico with high-potential worldwide exploration and development activities.

Anadarko's portfolio includes U.S. onshore assets in the lower 48 states and Alaska. The Company is also among the largest independent producers in the deepwater Gulf of Mexico and has exploration and production activities internationally, including activities in Algeria, Ghana, Mozambique, Colombia, Côte d'Ivoire, and other countries.

Anadarko is committed to producing energy in a manner that protects the environment and public health. Anadarko's focus is to deliver resources to the world while upholding the Company's core values of integrity and trust, servant leadership, people and passion, commercial focus, and open communication in all business activities.

Anadarko's business segments are managed separately due to distinct operational differences and unique technology, distribution, and marketing requirements. The Company's three reporting segments are as follows:

Oil and gas exploration and production—This segment explores for and produces oil, natural gas, and NGLs and plans for the development and operation of the Company's LNG project in Mozambique.

Midstream—This segment engages in gathering, processing, treating, and transporting Anadarko and third-party oil, natural-gas, and NGLs production as well as gathering and disposal of produced water. The Company owns and operates gathering, processing, treating, transportation, and produced-water disposal systems in the United States for oil, natural gas, NGLs, and produced water.

Marketing—This segment sells much of Anadarko's oil, natural-gas, and NGLs production as well as third-party purchased volumes. The Company actively markets oil, natural gas, and NGLs in the United States and oil, NGLs, and its anticipated LNG production from Mozambique internationally.

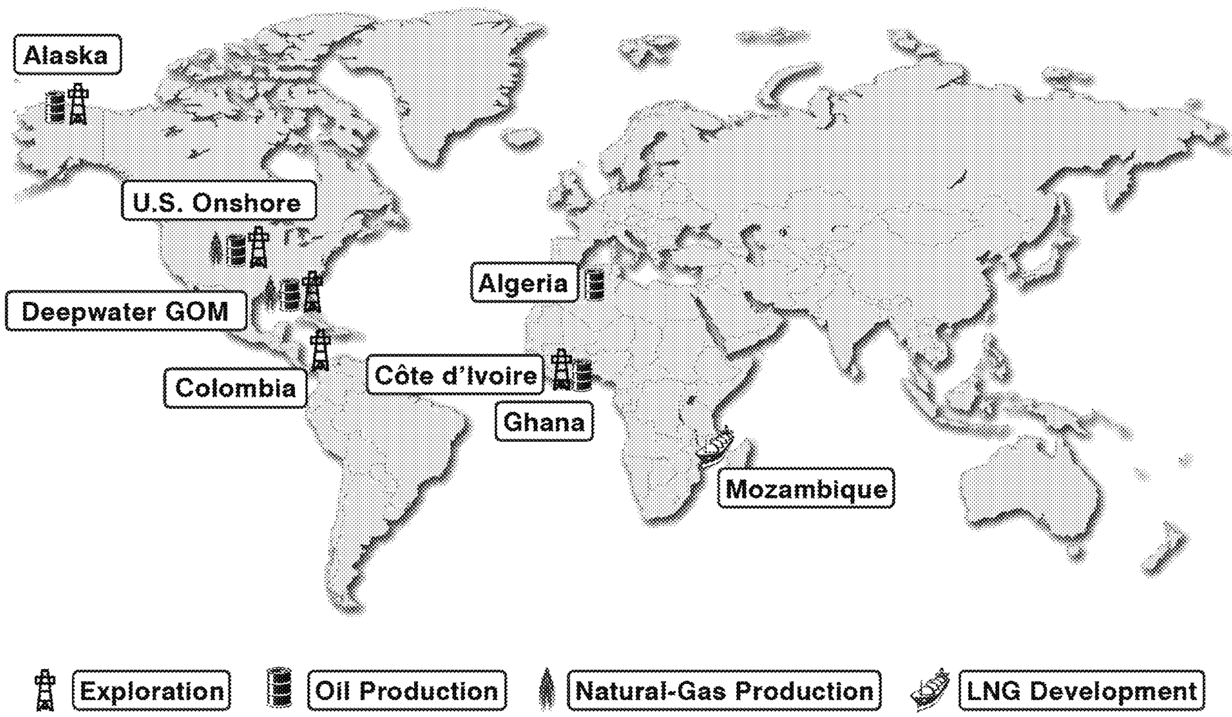
This Annual Report on Form 10-K and the documents incorporated herein by reference contain forward-looking statements based on expectations, estimates, and projections as of the date of this filing. These statements by their nature are subject to risks, uncertainties, and assumptions and are influenced by various factors. As a consequence, actual results may differ materially from those expressed in the forward-looking statements. See *Risk Factors* under Item 1A of this Form 10-K.

Available Information The Company's corporate headquarters is located at 1201 Lake Robbins Drive, The Woodlands, Texas 77380-1046, and its telephone number is (832) 636-1000. The Company files or furnishes Annual Reports on Form 10-K; Quarterly Reports on Form 10-Q; Current Reports on Form 8-K; registration statements, or any amendments thereto; and other reports and filings with the SEC. Anadarko provides access free of charge to all of these SEC filings, as soon as reasonably practicable after filing or furnishing, on its website located at investors.anadarko.com/sec-filings. The Company will also make available to any stockholder, without charge, printed copies of its Annual Report on Form 10-K as filed with the SEC. For copies of this Form 10-K, or any other filing, please contact Anadarko Petroleum Corporation, Investor Relations, P.O. Box 1330, Houston, Texas 77251-1330; call (855) 820-6605; send an email to investor@anadarko.com; or complete an information request on the Company's website at www.anadarko.com by selecting Investors/Shareholder Resources/Shareholder Services.

The public may read and copy any materials Anadarko files with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains a website at www.sec.gov that contains reports, proxy and information statements, and other information regarding issuers, including Anadarko, that file electronically with the SEC.

OIL AND GAS PROPERTIES AND ACTIVITIES

The map below illustrates the locations of Anadarko's significant oil and natural-gas exploration and production operations:

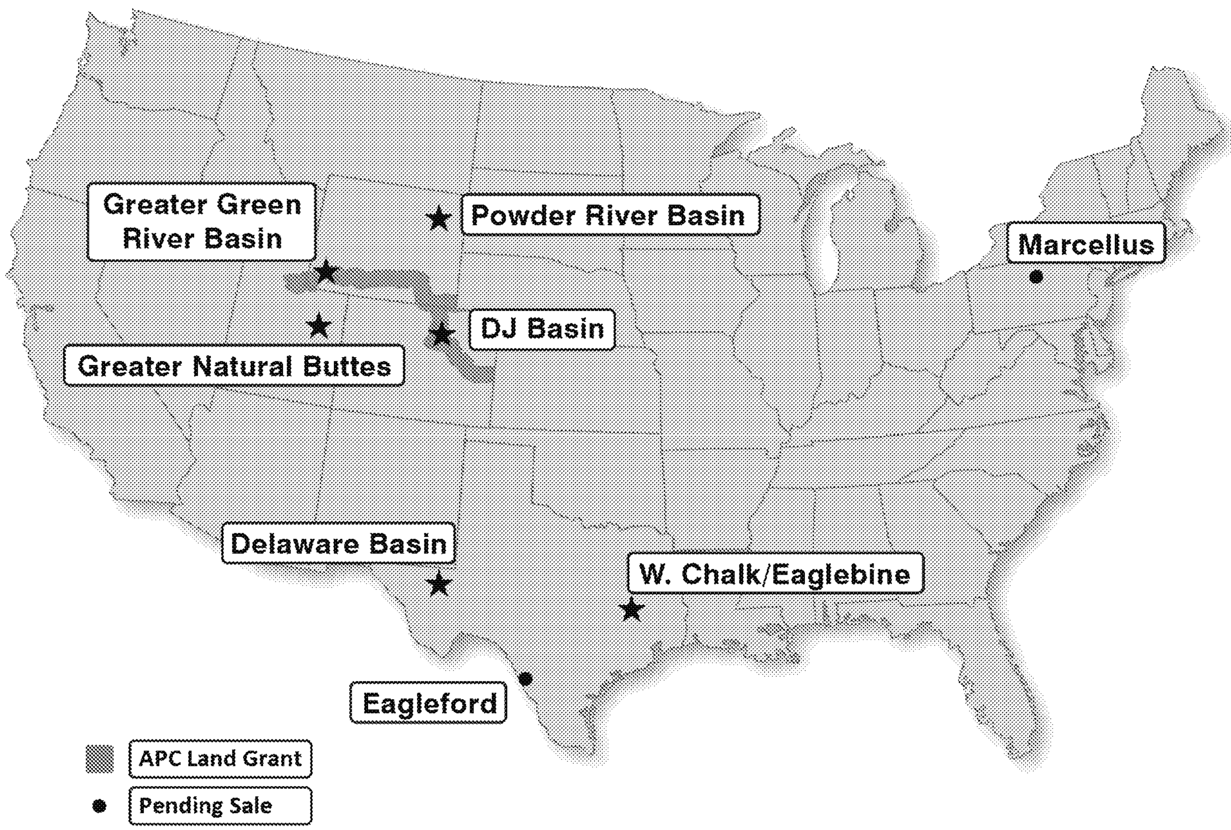


United States

Overview Anadarko's U.S. operations include oil and natural-gas exploration and production in the U.S. onshore, deepwater Gulf of Mexico, and Alaska. The Company's U.S. operations accounted for 89% of sales volumes and 80% of sales revenues during 2016 and 90% of proved reserves at year-end 2016.

U.S. Onshore Anadarko's U.S. onshore properties include oil and natural-gas plays located in Colorado, Texas, Utah, Wyoming, Pennsylvania, Louisiana, and Kansas, where the Company operates approximately 12,700 wells and owns interests in approximately 3,500 nonoperated wells.

The map below illustrates the locations of Anadarko's U.S. onshore oil and natural-gas exploration and production operations:



Activities in the U.S. onshore during 2016 primarily focused on adding reserves through horizontal drilling and infill drilling, optimizing wellbore and completion design, improving cost structure, delivering efficient production, and delineating positions in the Delaware and DJ basins. Process improvements and optimization projects assisted in providing both lower costs and cycle-time improvements. The Company drilled 207 wells and completed 384 wells in the U.S. onshore during 2016. The Company also divested non-core U.S. onshore assets, primarily in West Texas, East Texas/Louisiana, Wyoming, and Kansas and expects to divest additional non-core U.S. onshore assets during the first quarter of 2017 as discussed further below. In 2017, the Company expects to continue its horizontal drilling program, focusing on the Delaware and DJ basins.

The Company also has fee ownership of mineral rights, known as the Land Grant, under approximately eight million acres that pass through Colorado and Wyoming and into Utah. Management considers the Land Grant a significant competitive advantage for Anadarko as it enhances the Company's economic returns from production, offers drilling opportunities for the Company without expiration, and allows the Company to capture royalty revenue from third-party activity on Land Grant acreage.

Delaware Basin Anadarko holds interests in over 580,000 gross acres in the Delaware basin. Anadarko's 2016 drilling activity primarily targeted the Wolfcamp shale play, liquids-rich Bone Spring 2 tight sands, and Avalon shale play. In 2016, Anadarko drilled 103 operated wells and participated in 36 nonoperated wells. The full-year 2016 average drilling cost per foot was reduced by approximately 26% and drilling cycle time was reduced by 11% relative to 2015. Significant infrastructure continues to be added to facilitate future growth from this asset as discussed in *Midstream Properties and Activities*. The Company had 6 operated drilling rigs in the first quarter of 2016, ended 2016 with 9 operated drilling rigs, and expects to increase to 14 operated drilling rigs by the end of the first quarter of 2017.

The successful Wolfcamp shale delineation program continues to deliver encouraging results across the majority of Anadarko's acreage position. Anadarko is testing multiple zones within the Wolfcamp shale and several development concepts for increased efficiency. Included in these development concepts are multi-well pads, extended laterals, enhanced completion designs, and horizontal-well spacing. The Company has identified more than 7,000 potential short-lateral-equivalent drilling locations in the Wolfcamp formation that are expected to provide substantial opportunity for Anadarko's future activity in the basin.

DJ Basin Anadarko holds interests in over 350,000 net acres in its core position and operates approximately 5,200 vertical wells and 1,220 horizontal wells in the DJ basin. The field contains the Niobrara and Codell formations, which are naturally fractured formations that hold both liquids and natural gas. During 2016, the Company's drilling program focused entirely on horizontal development, drilling 91 horizontal wells. Horizontal drilling results in the field continue to be strong, with economics that are enhanced by the Company's ownership of the Land Grant and recent operational efficiencies in drilling and completions. In the second quarter of 2016, the Company commissioned its COSF, further discussed in *Midstream Properties and Activities*.

Drilling spud-to-rig-release cycle time average improved from 6.3 days in 2015 to 4.7 days in 2016. The full-year 2016 average drilling cost per foot was reduced by approximately 14% and completion capital was reduced by 23% relative to 2015. Operated well capital costs in 2016 have decreased to less than $2.5 million from approximately $3.5 million in 2015 for a short-lateral-equivalent well, driven by continued operational efficiencies and supply-chain savings. The Company had two operated drilling rigs in the first quarter of 2016, ended 2016 with five operated drilling rigs, and added a sixth drilling rig in January 2017.

Greater Natural Buttes The Greater Natural Buttes area in eastern Utah is one of the Company's major tight-gas assets. The Company has cryogenic and refrigeration processing facilities available in this area to extract NGLs from the natural-gas stream. The Company operated the field at a reduced activity level for the majority of 2016 due to capital being diverted to higher-margin projects. The Company operates approximately 2,930 wells in the area. Focus in the field shifted to increasing operating margins through the reduction of expenses and optimization of base production.

Eaglebine Anadarko holds 172,000 gross acres in the Eaglebine shale in Southeast Texas, most of which is held by existing Austin Chalk production. In 2016, Anadarko continued to delineate and develop this acreage by drilling five operated horizontal wells with a one-rig program. Under a carried-interest arrangement entered into in 2014, which requires a third party to fund $442 million of Anadarko's capital costs in exchange for a 34% working interest in the Eaglebine development, Anadarko has generated positive cash flow in the challenged price environment of 2016. As of December 31, 2016, $151 million of the total $442 million carry obligation had been funded.

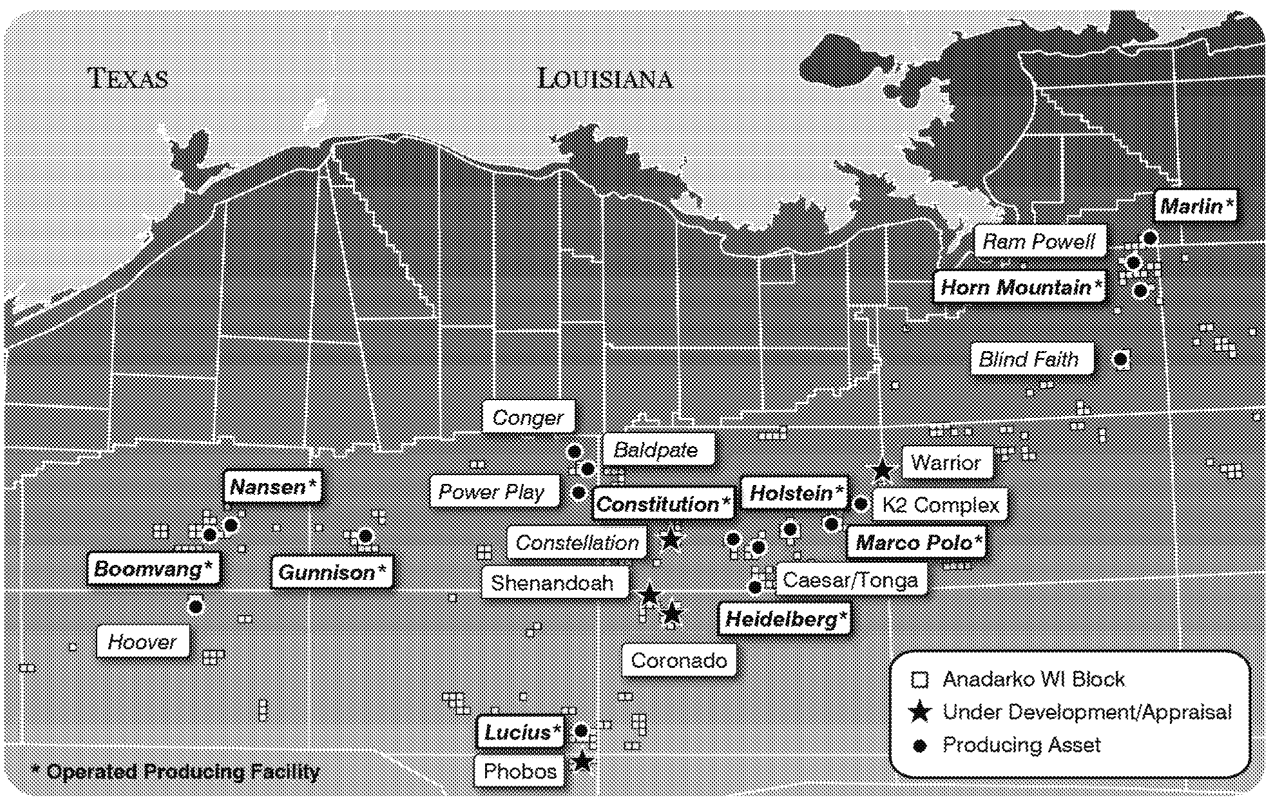
Greater Green River Basin Anadarko operates over 960 wells in the Moxa field in Wyoming and also carries a nonoperated position in 430 wells. Much of this producing area is located within the Land Grant, which enhances the Company's economics in projects in the area. During 2016, Anadarko drilled and completed three carried exploration wells on the Land Grant.

Marcellus The Company holds 195,000 net acres in the Marcellus shale of the Appalachian basin. In 2016, Anadarko participated in the drilling of two nonoperated horizontal wells. During the year, the field focused on water management and well optimization, decreasing expenses and increasing margins. In December 2016, the Company entered into an agreement to sell its Marcellus oil and natural-gas assets and certain related midstream assets for approximately $1.2 billion. This transaction is expected to close in the first quarter of 2017.

Eagleford The Eagleford shale development in South Texas consists of approximately 155,000 net acres and over 1,400 producing wells. In 2016, the Company drilled 3 wells, completed 29 wells, and brought 74 wells online. In the last three quarters of 2016, the field shifted its focus to base production optimization by completing an artificial lift program that improved performance and continued optimization of its infield gathering system. In January 2017, the Company entered into an agreement to sell its Eagleford oil and natural-gas assets for approximately $2.3 billion. This transaction is expected to close in the first quarter of 2017.

Gulf of Mexico Including the GOM Acquisition described below, as of December 31, 2016, Anadarko owns an average working interest of 70% in 327 blocks in the Gulf of Mexico, operates 10 active floating platforms, and holds interests in 39 fields. The Company continued an active deepwater development and appraisal program in the Gulf of Mexico during 2016 as it continues to take advantage of existing infrastructure to cost-effectively develop known resources.

The map below illustrates the locations of Anadarko's Gulf of Mexico oil and natural-gas exploration and production operations:



Acquisition

In December 2016, the Company closed the GOM Acquisition for approximately $1.8 billion using net proceeds from the September 2016 issuance of 40.5 million shares of its common stock. The GOM Acquisition expanded Anadarko's operated infrastructure in the region, doubling its net oil production from the Gulf of Mexico to more than 160 MBbls/d. The GOM Acquisition doubled the Company's ownership in the Lucius development, increased its ownership in the Company's Heidelberg asset, and resulted in a 100% working interest in the Horn Mountain, Marlin, and Holstein fields. Drilling is expected to begin in the first quarter of 2017 on the newly acquired assets, which each have multiple high-quality tie-back opportunities. The acquired assets are expected to generate substantial cash flow over the next five years at current strip prices, enabling accelerated investment in Anadarko's Delaware and DJ basin assets.

Development

Lucius The Company successfully drilled and completed the seventh development well in 2016. The well encountered 475 net feet of high-quality oil pay and was brought online in early 2016. The field continues to demonstrate favorable connectivity and strong aquifer support, improving well deliverability. The spar, located in Keathley Canyon Block 875 at a water depth of 7,000 feet, reached peak production of more than 100 MBbls/d of oil in 2016, exceeding the facility nameplate capacity of 80 MBbls/d. The Company more than doubled its interest in the field from 23.8% to approximately 49% through the GOM Acquisition. Anadarko expects to drill and complete the eighth development well in 2017.

Caesar/Tonga At Caesar/Tonga (33.75% working interest), the Company successfully drilled and completed a sixth development well, which came online in the first quarter of 2016. Anadarko also successfully completed a seventh development well in 2016, which encountered more than 500 net feet of oil pay and began producing in the second quarter of 2016. Continued success at Caesar/Tonga resulted in peak production of more than 60 MBbls/d of oil. The Company sanctioned a Phase 2 development plan during the fourth quarter of 2015 and manufactured and installed subsea infrastructure in 2016.

Constellation The Company acquired a 33.33% operated working interest in the Constellation discovery (formerly Hopkins) and was named operator after reaching a co-development agreement with a third party. Development drilling is expected to begin in 2017, and the field is expected to be tied back to Anadarko's Constitution spar.

K2 Complex At K2 (41.8% working interest), the GC 561#3 development well, drilled in the second quarter of 2015, found 331 net feet of oil pay and was brought online in the second quarter of 2016. The GC 562#6 development well was drilled and completed in 2016, with production anticipated in the second quarter of 2017.

Heidelberg The Company realized first production at the Anadarko-operated Heidelberg spar in January 2016, when the first three wells were brought online. The fourth well, which encountered 185 net feet of oil pay, came online in the third quarter of 2016. After encountering water in its first penetration, the fifth well was sidetracked and encountered 191 net feet of oil pay. The Company expects the well to be brought online in the first quarter of 2017.

In 2013, the Company entered into a carried-interest arrangement requiring a third party to fund $860 million of capital costs in exchange for a 12.75% working interest in the project. The carry commitment covered the majority of Anadarko's capital costs through first production. In the third quarter of 2016, all of the carry obligation had been funded. The Company increased its working interest in the field from 31.5% to 44% through the GOM Acquisition.

Appraisal

Shenandoah Anadarko and its partners are continuing to work toward determining the commerciality of the Shenandoah field. The Company has selected a Semisubmersible concept to support the potential development as part of these efforts. The front-end engineering design (FEED) on the Semisubmersible will continue while Anadarko continues appraisal drilling to further delineate the opportunity before making a future sanctioning decision.

The Company spud the Shenandoah-5 well, the fourth appraisal well at the Shenandoah discovery (33% working interest), in the first quarter of 2016. The well encountered more than 1,040 net feet of oil pay, extending the resource in the central-to-eastern limits of the field. The well has been secured for potential future production operations. The Shenandoah-6 appraisal well was spud in the fourth quarter of 2016. The drilling objective is to establish the oil-water contact on the eastern flank of the field and to help quantify the resource potential of the basin. During 2016, Anadarko increased its working interest in Shenandoah from 30% to 33% by participating in a preferential-right process.

Phobos The Phobos appraisal well (100% working interest) encountered more than 90 net feet of oil pay in the secondary objective Pliocene-aged reservoir and approximately 130 net feet of oil pay from the primary objective Wilcox-aged reservoirs. Phobos is located approximately 12 miles south of the Anadarko-operated Lucius facility. Phobos is currently being evaluated as a tie-back candidate to the Anadarko-operated Lucius spar.

Exploration

Warrior The Warrior exploration well (65% working interest) encountered more than 210 net feet of oil pay in multiple high-quality Miocene-aged reservoirs. The Warrior discovery is located approximately three miles from the Anadarko-operated K2 field and is expected to be tied back to the Marco Polo production facility. Anadarko expects to drill the first appraisal well in 2017.

Alaska Anadarko's nonoperated (22% working interest) oil production and development activity in Alaska is concentrated on the North Slope. Gross production from the Colville River Unit averaged approximately 60 MBbls/d of oil during the fourth quarter of 2016.

The operator completed an active drilling campaign in 2016, including nine development wells, one appraisal well, and two successful exploration wells. The Willow oil discovery was announced by the operator during the first quarter of 2017. Initial production could occur as early as 2023 subject to appraisal results, development planning, and timely permit approvals.

International

Overview Anadarko's international operations include oil, natural-gas, and NGLs production and development in Algeria and Ghana, along with activities in Mozambique, where the Company continues to make progress towards a final investment decision on an LNG development. The Company also has exploration acreage in Colombia, Côte d'Ivoire, Mozambique, and other countries. International locations accounted for 11% of Anadarko's sales volumes and 20% of sales revenues during 2016 and 10% of proved reserves at year-end 2016. In 2017, the Company expects to focus its exploration and appraisal activity in Côte d'Ivoire and Colombia.

Algeria Anadarko is engaged in production and development operations in Algeria's Sahara Desert in Blocks 404 and 208, which are governed by a Production Sharing Agreement between Anadarko, Sonatrach, and other partners. The Company is responsible for 24.5% of the development and production costs for these blocks. The Company produces oil through the Hassi Berkine South and Ourhoud central processing facilities (CPFs) in Block 404 and oil and NGLs through the El Merk CPF in Block 208. Gross production through these facilities averaged more than 376 MBbls/d in 2016, an increase of 8 MBbls/d from 2015. Production increases were driven by reservoir optimization at El Merk and completion of an increased water-handling project at the Ourhoud CPF, which doubled the water and gas handling capacities. The Company drilled two development wells in 2016. Late in 2016, members of OPEC agreed to reduce production output for the first six months of 2017. Anadarko expects minimal production impact from this reduction.

Ghana Anadarko's production and development activities in Ghana are located offshore in the West Cape Three Points Block and the Deepwater Tano Block.

The Jubilee field (27% nonoperated participating interest), which spans both the West Cape Three Points Block and the Deepwater Tano Block, averaged gross production of 74 MBbls/d of oil in 2016. An average of 59 MMcf/d of natural gas was exported from the Jubilee field to an onshore gas processing plant in satisfaction of a commitment established in conjunction with the Jubilee development plan. In 2016, the operator announced that damage to the FPSO turret bearing had occurred. As a result, new production and offtake procedures were implemented, and the partners agreed to a long-term solution to convert the FPSO to a permanently-moored facility. Interim mooring of the vessel commenced in the fourth quarter of 2016 and is expected to be completed during the first quarter of 2017. Final decisions and approvals will be sought for the long-term turret system solution in the first half of 2017. It is anticipated that a facility shutdown of up to 12 weeks may be required in the second half of 2017. The partnership is actively seeking optimization solutions to minimize the duration of any shutdown period. Including the impact of the potential facility shutdown, the operator expects the average gross production from the Jubilee field to be more than 68 MBbls/d in 2017.

The TEN project (19% nonoperated participating interest) is located in the Deepwater Tano Block. The TEN project uses an 80 MBbls/d-capacity FPSO for production from subsea wells. The project achieved first oil in the third quarter of 2016 and first liftings during the fourth quarter of 2016. Production rates ramped up from first production through the fourth quarter to a December 2016 average of approximately 54 MBbls/d.

Mozambique Anadarko operates Offshore Area 1 (26.5% participating interest), which totals approximately 1.2 million gross acres. The Company is progressing three elements that will position the project for execution and deliver future value: the legal and contractual framework to develop LNG in Mozambique, project finance, and long-term LNG sales contracts.

Development Anadarko continues to engage with the Government of Mozambique to conclude the legal and contractual framework required to support investment. The foundation for the legal and contractual framework is the Decree Law published in 2014 and ratified in July 2015. The Company continues to work with construction and installation contractors to identify opportunities to optimize costs and reduce execution risk once the project progresses to the construction phase. In 2016, Anadarko and its partners formally launched the project financing process and continued to progress significant LNG long-term sales contracts. During the fourth quarter of 2016, the Government of Mozambique approved the Resettlement Plan that was submitted in June 2016. This marks a critical step on the path to commence resettlement implementation, which will facilitate clearance of the project site to begin construction of the LNG facility. The Development Plan for the initial two-train onshore project was submitted to the Government of Mozambique in the fourth quarter of 2016.

Exploration In Offshore Area 1, the Company continues to reprocess 3D seismic data covering the Orca, Tubarão, and Tubarão Tigre discovery areas, in accordance with the appraisal program submitted to the Government of Mozambique in the first quarter of 2015.

Colombia Anadarko controls the exclusive rights to explore or conduct technical evaluation activities on eight blocks totaling approximately 15 million gross acres. The COL 1, COL 2, COL 6, and COL 7 blocks are operated at a 100% working interest, and the blocks in the Grand Fuerte area are operated at a 50% working interest.

In the Grand Fuerte area, the Purple Angel-1 exploration well (50% working interest) spud during the fourth quarter of 2016, and operations are ongoing. The well is designed to test objectives similar to those at Anadarko's 2015 play-opening Kronos discovery. The rig will mobilize to drill the Gorgon prospect, also located in the Purple Angel Block, following the completion of operations at the Purple Angel-1 well. The Gorgon-1 exploration well will test an analogous structure along trend to the Kronos discovery.

In the Grand COL area, acquisition of the approximately 30-thousand km^2 Esmeralda 3D seismic survey was completed in the third quarter of 2016.

Côte d'Ivoire Anadarko owns an operated working interest in four offshore blocks totaling approximately 1.0 million gross acres, including CI-103, with a 65% working interest, and CI-527, CI-528, and CI-529, each with a 90% working interest.

Appraisal At Paon (CI-103), appraisal continued in 2016. The Paon-5A horizontal well, Anadarko's first horizontal deepwater well, encountered nearly 100 net feet of oil pay, successfully appraising the discovery. A second deepwater horizontal well was drilled at the Paon-3AR sidetrack and encountered approximately 120 net feet of oil pay. Following the appraisal drilling campaign, Anadarko completed a successful drillstem and interference testing program at Paon.

Exploration Two exploration wells were drilled to the southeast of Paon during 2016, targeting similar-aged sands along trend to the Paon discovery. The Rossignol-1X well (CI-528) encountered well-developed sands and found approximately 15 feet of net oil pay on water. The Pelican-1X well (CI-527) encountered approximately 70 feet of net oil pay in two separate intervals. Anadarko is currently evaluating its 2017 Côte d'Ivoire drilling program.

Other Anadarko also holds exploration interests in other offshore international areas including Canada, Kenya, New Zealand, and South Africa, among others.

Proved Reserves

Estimates of proved reserves volumes owned at year end, net of third-party royalty interests, are presented in Bcf at a pressure base of 14.73 pounds per square inch for natural gas and in MMBbls for oil and NGLs. Total volumes are presented in MMBOE. For this computation, one barrel is the equivalent of 6,000 cubic feet of natural gas. Shrinkage associated with NGLs has been deducted from the natural-gas reserves volumes. Proved reserves are estimated based on the average beginning-of-month prices during the 12-month period for the respective year.

Disclosures by geographic area include the United States and International. For 2016, the International geographic area consisted of proved reserves located in Algeria and Ghana, which by country and in total represented less than 15% of the Company's total proved reserves.

Summary of Proved Reserves

	Oil (MMBbls)	Natural Gas (Bcf)	NGLs (MMBbls)	Total (MMBOE)
December 31, 2016				
Proved				
Developed				
United States	**360**	**3,637**	**193**	**1,159**
International	**147**	**25**	**15**	**166**
Undeveloped				
United States	**181**	**762**	**75**	**383**
International	**14**	**—**	**—**	**14**
Total proved	**702**	**4,424**	**283**	**1,722**
December 31, 2015				
Proved				
Developed				
United States	332	5,184	257	1,453
International	159	30	15	179
Undeveloped				
United States	193	807	68	396
International	29	—	—	29
Total proved	713	6,021	340	2,057
December 31, 2014				
Proved				
Developed				
United States	352	6,635	304	1,762
International	190	27	13	207
Undeveloped				
United States	352	2,033	162	853
International	35	4	—	36
Total proved	929	8,699	479	2,858

The Company's proved reserves product mix increased to 57% liquids in 2016, compared to 52% in 2015 and 49% in 2014. The Company's year-end 2016 proved reserves product mix was 40% oil, 43% natural gas, and 17% NGLs.

Changes to the Company's proved reserves during 2016 are summarized in the table below:

MMBOE	**2016**	2015	2014
Proved Reserves			
January 1	**2,057**	2,858	2,792
Reserves additions and revisions			
Discoveries and extensions	**40**	29	63
Infill-drilling additions [(1)]	**69**	89	577
Drilling-related reserves additions and revisions	**109**	118	640
Other non-price-related revisions [(1)]	**191**	289	(137)
Net organic reserves additions	**300**	407	503
Acquisition of proved reserves in place	**97**	1	—
Price-related revisions [(1)]	**(147)**	(624)	(1)
Total reserves additions and revisions	**250**	(216)	502
Sales in place	**(294)**	(279)	(124)
Production	**(291)**	(306)	(312)
December 31	**1,722**	2,057	2,858
Proved Developed Reserves			
January 1	**1,632**	1,969	2,003
December 31	**1,325**	1,632	1,969

(1) Combined and reported as revisions of prior estimates in the Company's *Supplemental Information on Oil and Gas Exploration and Production Activities (Supplemental Information)* under Item 8 of this Form 10-K. Reserves related to infill-drilling additions are treated as positive revisions. Price-related revisions reflect the impact of current prices on the reserves balance at the beginning of each year. Other non-price-related revisions in 2016 are primarily a reflection of performance improvements coupled with the benefit of reduced year-end costs.

Proved reserves are estimated based on the average beginning-of-month prices during the 12-month period for the respective year. The average prices used to compute proved reserves at December 31, 2016, were $42.75 per Bbl for oil, $2.48 per MMBtu for natural gas, and $19.74 per Bbl for NGLs.

The Company's estimates of proved developed reserves, PUDs, and total proved reserves at December 31, 2016, 2015, and 2014, and changes in proved reserves during the last three years are presented in the *Supplemental Information* under Item 8 of this Form 10-K. Also presented in the *Supplemental Information* are the Company's estimates of future net cash flows and discounted future net cash flows from proved reserves. See *Critical Accounting Estimates* under Item 7 of this Form 10-K for additional information on the Company's proved reserves.

The Company has not yet filed information with a federal authority or agency with respect to its estimated total proved reserves at December 31, 2016. Annually, Anadarko reports gross proved reserves for U.S.-operated properties to the U.S. Department of Energy. These reported reserves are derived from the same database used to estimate and report proved reserves in this Form 10-K.

Changes in PUDs Changes to PUDs during 2016 are summarized in the table below. The Company's year-end development plans and associated PUDs are consistent with SEC guidelines for PUDs development within five years unless specific circumstances warrant a longer development time horizon.

MMBOE	
PUDs at January 1, 2016	**425**
Revisions of prior estimates	**70**
Extensions, discoveries, and other additions	**5**
Conversions to developed	**(118)**
Purchases	**30**
Sales	**(15)**
PUDs at December 31, 2016	**397**

Revisions Revisions of prior estimates reflect Anadarko's ongoing evaluation of its asset portfolio. In 2016, PUDs were revised upward by 70 MMBOE.

MMBOE	**December 31, 2016**
Revisions due to changes in year-end prices (price impact to opening balance)	**(74)**
Other revisions of prior estimates	
Revisions due to performance	**10**
Revisions due to cost reductions	**53**
Revisions due to successful infill drilling	**60**
Revisions due to development plan updates	**3**
Other revisions	**18**
Total other revisions of prior estimates	**144**
Revisions of prior estimates	**70**

Negative revisions of 74 MMBOE were due to the decline in commodity prices. The negative price-related revisions were offset by a net increase of 144 MMBOE associated with the following:

- *Performance* The Company experienced an increase in PUDs primarily due to improved well performance in the DJ basin and U.S. shale play areas.

- *Cost reductions* Ongoing cost-optimization efforts and a reduced cost structure associated with the lower commodity-price environment resulted in an increase in PUDs. The DJ basin and Eagleford areas experienced an increase of 45 MMBOE of PUDs associated with certain wells, included in the negative price-related revisions, which experienced restored economic producibility upon reduction of the cost structure. The remaining increase in PUDs due to the improved cost structure is attributable to several other areas across the Company.

- *Infill drilling* The Company added 60 MMBOE of infill PUDs during 2016, with a majority of the additions in the DJ basin and the K2 and Caesar/Tonga areas of the Gulf of Mexico.

- *Other revisions* Certain projects that had negative price-related revisions associated with the opening PUDs balance were also either converted to developed status during the year or moved to other unproved categories, primarily as a result of changes to development plans. In an effort to provide full transparency of price sensitivity, the price-related revisions and these other changes were disclosed completely and independently rather than as a net impact. The multi-step process to reconcile and explain changes in reserves resulted in an immaterial duplicative reduction of reserves. These other revisions eliminate the duplicative adjustments to the opening reserves balance.

Extensions, Discoveries, and Other Additions During 2016, Anadarko added PUDs through the extension of proved acreage, primarily as a result of successful drilling in the Lucius area of the Gulf of Mexico and the Marcellus shale play.

Conversions In 2016, the Company converted 118 MMBOE of PUDs to developed status, equating to 25% of total year-end 2015 PUDs when adjusted for revisions and sales. Approximately 55% of PUDs conversions occurred in U.S. onshore assets, 32% occurred in Gulf of Mexico assets, and the remaining 13% occurred in international assets.

Anadarko spent $0.9 billion to develop PUDs in 2016, of which approximately 50% related to U.S. onshore assets, including Alaska; 27% related to Gulf of Mexico assets; and 23% related to international assets.

Purchases In 2016, PUDs increased by 30 MMBOE due to the GOM Acquisition.

Sales In 2016, PUDs decreased due to the Company's divestiture activities in U.S. onshore areas.

Development Plans The Company annually reviews all PUDs to ensure an appropriate plan for development exists. Typically, U.S. onshore PUDs are converted to developed reserves within five years of the initial proved reserves booking, but projects associated with arctic development, deepwater development, and international programs may take longer. At December 31, 2016, the Company had no material pre-2012 PUDs that remained undeveloped.

Technologies Used in Proved Reserves Estimation The Company's 2016 proved reserves additions were based on estimates generated through the integration of relevant geological, engineering, and production data, using technologies that have been demonstrated in the field to yield repeatable and consistent results as defined in the SEC regulations. Data used in these integrated assessments included information obtained directly from the subsurface through wellbores such as well logs, reservoir core samples, fluid samples, static and dynamic pressure information, production test data, and surveillance and performance information. The data used also included subsurface information obtained through indirect measurements such as seismic data. The tools used to interpret the data included proprietary and commercially available seismic processing software and commercially available reservoir modeling and simulation software. Reservoir parameters from analogous reservoirs were used to increase the quality of and confidence in the reserves estimates when available. The method or combination of methods used to estimate the reserves of each reservoir was based on the unique circumstances of each reservoir and the dataset available at the time of the estimate.

Internal Controls over Reserves Estimation Anadarko's estimates of proved reserves and associated future net cash flows were made solely by the Company's engineers and are the responsibility of management. The Company requires that reserves estimates be made by qualified reserves estimators (QREs) as defined by the Society of Petroleum Engineers' standards. The QREs are assigned to specific assets within the Company's regions. The QREs interact with engineering, land, and geoscience personnel to obtain the necessary data for projecting future production, net cash flows, and ultimate recoverable reserves. Management within each region approves the QREs' reserves estimates. All QREs receive ongoing education on the fundamentals of SEC definitions and reserves reporting through the Company's reserves manual and internal training programs administered by the Corporate Reserves Group (CRG).

The CRG ensures confidence in the Company's reserves estimates by maintaining internal policies for estimating and recording reserves in compliance with applicable SEC definitions and guidance. Compliance with the SEC reserves guidelines is the primary responsibility of Anadarko's CRG.

The CRG is managed through the Company's finance department, which is separate from its operating regions, and is responsible for overseeing internal reserves reviews and approving the Company's reserves estimates. The Director of Corporate Reserves manages the CRG and reports to the VP—Corporate Planning. The VP—Corporate Planning reports to the Company's Executive Vice President, Finance and Chief Financial Officer, who in turn reports to the Chairman, President, and Chief Executive Officer. The Governance and Risk Committee of the Company's Board meets with management, members of the CRG, and the Company's independent petroleum consultants, Miller and Lents, Ltd. (M&L), to discuss the results of procedures and methods reviews as discussed below as well as other matters and policies related to reserves.

The Company's principal engineer, who is primarily responsible for overseeing the preparation of proved reserves estimates, has over 30 years of experience in the oil and gas industry, including over 16 years as either a reserves estimator or manager. His further professional qualifications include a degree in petroleum engineering, extensive internal and external reserves training, and asset evaluation and management. The principal engineer is a member of the Society of Petroleum Engineers, where he has been a member for over 30 years, and is also a member of the Society of Petroleum Evaluation Engineers. In addition, he is an active participant in industry reserves seminars and professional industry groups.

Third-Party Procedures and Methods Reviews M&L reviewed the procedures and methods used by Anadarko's staff in preparing the Company's estimates of proved reserves and future net cash flows at December 31, 2016. The purpose of the review was to determine if the procedures and methods used by Anadarko to estimate its proved reserves are effective and in accordance with the definitions contained in SEC regulations. The procedures and methods reviews by M&L were limited reviews of Anadarko's procedures and methods and do not constitute a complete review, audit, independent estimate, or confirmation of the reasonableness of Anadarko's estimates of proved reserves and future net cash flows.

The reviews covered 14 fields that included major assets in the United States and Africa and encompassed approximately 86% of the Company's estimates of proved reserves and associated future net cash flows at December 31, 2016. In each review, Anadarko's technical staff presented M&L with an overview of the data, methods, and assumptions used in estimating its reserves. The data presented included pertinent seismic information, geologic maps, well logs, production tests, material balance calculations, reservoir simulation models, well performance data, operating procedures, and relevant economic criteria.

Management's intent in retaining M&L to review its procedures and methods is to provide objective third-party input on the Company's procedures and methods and to gather industry information applicable to reserves estimation and reporting processes.

Sales Volumes, Prices, and Production Costs

The following provides the Company's annual sales volumes, average sales prices, and average production costs per BOE for each of the last three years:

	Sales Volumes				Average Sales Prices [1]			
	Oil (MMBbls)	Natural Gas (Bcf)	NGLs (MMBbls)	Barrels of Oil Equivalent (MMBOE)	Oil (Per Bbl)	Natural Gas (Per Mcf)	NGLs (Per Bbl)	Average Production Costs [2] (Per BOE)
2016								
United States								
Wattenberg (DJ basin)	**33**	**214**	**20**	**89**	**40.27**	**2.00**	**18.26**	**8.41**
Other United States	**52**	**552**	**24**	**168**	**38.29**	**2.06**	**20.21**	**6.80**
Total United States	**85**	**766**	**44**	**257**	**39.06**	**2.04**	**19.32**	**7.36**
International	**31**	**—**	**2**	**33**	**43.93**	**—**	**25.63**	**7.93**
Total	**116**	**766**	**46**	**290**	**40.34**	**2.04**	**19.64**	**7.42**
2015								
United States								
Wattenberg (DJ basin)	35	176	16	81	44.88	2.31	15.65	8.21
Other United States	50	676	29	191	45.08	2.37	17.83	8.55
Total United States	85	852	45	272	45.00	2.36	17.03	8.45
International	31	—	2	33	51.68	—	29.85	7.22
Total	116	852	47	305	46.79	2.36	17.61	8.31
2014								
United States								
Wattenberg (DJ basin)	27	125	13	62	87.76	4.19	36.46	8.28
Other United States	47	820	30	213	88.13	4.05	35.03	9.04
Total United States	74	945	43	275	87.99	4.07	35.48	8.87
International	32	—	1	33	99.79	—	56.16	8.22
Total	106	945	44	308	91.58	4.07	36.01	8.80

(1) Excludes the impact of commodity derivatives.
(2) Excludes ad valorem and severance taxes.

Production costs are costs to operate and maintain the Company's wells, related equipment, and supporting facilities, including the cost of labor, well service and repair, location maintenance, power and fuel, gathering, processing, transportation, other taxes, and production-related general and administrative costs. Additional information on volumes, prices, and production costs is contained in *Financial Results* under Item 7 of this Form 10-K. Additional detail regarding production costs is contained in the *Supplemental Information* under Item 8 of this Form 10-K.

Delivery Commitments

The Company sells oil and natural gas under a variety of contractual agreements, some of which specify the delivery of fixed and determinable quantities. At December 31, 2016, Anadarko was contractually committed to deliver approximately 872 Bcf of natural gas to various customers in the United States through 2031. These contracts have various expiration dates, with approximately 36% of the Company's current commitment to be delivered in 2017 and 79% by 2021. At December 31, 2016, Anadarko was also contractually committed to deliver approximately 40 MMBbls of oil to a customer in the United States through 2020. These contracts have various expiration dates, with approximately 40% of the Company's current commitment to be delivered in 2017 and 100% by 2020. At December 31, 2016, Anadarko also was contractually committed to deliver approximately 10 MMBbls of oil to ports in Algeria and Ghana through 2017. The Company expects to fulfill these delivery commitments with existing proved developed reserves and PUDs, which the Company regularly monitors to ensure sufficient availability to meet its commitments. If production is not sufficient to meet contractual delivery commitments, the Company may purchase commodities in the market to satisfy its delivery commitments.

Properties and Leases

The following shows the developed lease, undeveloped lease, and fee mineral acres in which Anadarko held interests at December 31, 2016:

	Developed Lease		Undeveloped Lease		Fee Mineral [1]		Total	
thousands of acres	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
United States								
Onshore	3,230	1,896	2,976	1,127	9,906	8,212	16,112	11,235
Offshore	351	198	1,525	1,144	—	—	1,876	1,342
Total United States	3,581	2,094	4,501	2,271	9,906	8,212	17,988	12,577
International	611	132	46,315	32,481	—	—	46,926	32,613
Total	4,192	2,226	50,816	34,752	9,906	8,212	64,914	45,190

(1) The Company's fee mineral acreage is primarily undeveloped.

At December 31, 2016, the Company had approximately six million net undeveloped lease acres scheduled to expire by December 31, 2017, if the Company does not establish production or take any other action to extend the terms. The Company plans to continue the terms of many of these licenses and concession areas through operational or administrative actions. The net undeveloped lease acres scheduled to expire by December 31, 2017, primarily relate to 5.8 million net acres of international exploration acreage in New Zealand (2.0 million net acres), Kenya (1.8 million net acres), Colombia (1.1 million net acres), and Côte d'Ivoire (0.9 million net acres), where proved reserves have not been assigned. The Company does not expect a significant portion of its total net acreage position to expire in 2017.

Drilling Program

The Company's 2016 drilling program focused on proven and emerging liquids-rich basins in the United States (onshore and deepwater Gulf of Mexico) and various international locations. Exploration activity in 2016 consisted of 11 gross completed U.S. onshore wells. Development activity in 2016 consisted of 516 gross completed wells, which included 494 U.S. onshore wells, 13 international wells, and 9 Gulf of Mexico wells.

Drilling Statistics

The following shows the number of oil and gas wells completed in each of the last three years:

	Net Exploratory			Net Development			
	Productive	**Dry Holes**	**Total**	**Productive**	**Dry Holes**	**Total**	**Total**
2016							
United States	**3.7**	**1.2**	**4.9**	**322.1**	**—**	**322.1**	**327.0**
International	**—**	**1.8**	**1.8**	**2.9**	**—**	**2.9**	**4.7**
Total	**3.7**	**3.0**	**6.7**	**325.0**	**—**	**325.0**	**331.7**
2015							
United States	16.0	—	16.0	573.1	13.8	586.9	602.9
International	2.4	0.4	2.8	1.8	—	1.8	4.6
Total	18.4	0.4	18.8	574.9	13.8	588.7	607.5
2014							
United States	35.6	1.6	37.2	811.4	6.0	817.4	854.6
International	0.9	4.5	5.4	—	—	—	5.4
Total	36.5	6.1	42.6	811.4	6.0	817.4	860.0

The following shows the number of wells in the process of drilling or in active completion stages and the number of wells suspended or waiting on completion at December 31, 2016:

	Wells in the process of drilling or in active completion		Wells suspended or waiting on completion (1)	
	Exploration	**Development**	**Exploration**	**Development (2)**
United States				
Gross	3	9	51	643
Net	2.1	5.8	21.9	375.3
International				
Gross	2	—	54	11
Net	1.0	—	17.4	2.6
Total				
Gross	5	9	105	654
Net	3.1	5.8	39.3	377.9

(1) Wells suspended or waiting on completion include exploration and development wells where drilling has occurred, but the wells are awaiting the completion of hydraulic fracturing or other completion activities or the resumption of drilling in the future.

(2) There were 106 MMBOE of PUDs assigned to U.S. onshore development wells suspended or waiting on completion at December 31, 2016. The Company expects to convert these reserves to developed status within five years of their initial disclosure.

Productive Wells

At December 31, 2016, the Company's ownership interest in productive wells was as follows:

	Oil Wells [1]	Gas Wells [1]
United States		
Gross	3,949	12,615
Net	2,505.9	9,518.6
International		
Gross	208	9
Net	37.4	2.2
Total		
Gross	4,157	12,624
Net	2,543.3	9,520.8

[1] Includes wells containing multiple completions as follows:

Gross	209	2,405
Net	182.4	2,089.0

MIDSTREAM PROPERTIES AND ACTIVITIES

Anadarko invests in and operates midstream (gathering, processing, treating, transportation, and produced-water disposal) assets to complement its operations in regions where the Company has oil and natural-gas production. Through ownership and operation of these facilities, the Company improves its ability to manage costs, controls the timing of bringing on new production, and enhances the value received for gathering, processing, treating, and transporting the Company's production. Anadarko's midstream business also provides services to third-party customers, including major and independent producers. Anadarko generates revenues from its midstream activities through a variety of contract structures, including fixed-fee, percent-of-proceeds, wellhead purchase, and keep-whole agreements. Anadarko's midstream activities include those of WES, which acquires, owns, develops, and operates midstream assets. At December 31, 2016, Anadarko's ownership interest in WGP consisted of an 81.6% limited partner interest and the entire non-economic general partner interest. At December 31, 2016, WGP's ownership interest in WES consisted of a 29.9% limited partner interest, the entire 1.5% general partner interest, and all of the WES incentive distribution rights. At December 31, 2016, Anadarko also owned an 8.6% limited partner interest in WES through other subsidiaries.

At the end of 2016, Anadarko had 34 gathering systems and 72 processing and treating facilities located throughout major onshore producing basins in Wyoming, Colorado, Utah, New Mexico, Pennsylvania, and Texas. In 2016, the Company's midstream activity was concentrated in the Delaware basin to build infrastructure for present and future Wolfcamp development. In 2017, the Company expects to continue its midstream investment to focus on the Delaware and DJ basins.

Delaware Basin In 2016, the Company expanded its midstream infrastructure for Bone Spring, Wolfcamp, and Avalon production in the Delaware basin of West Texas, installing over 200 miles of oil, water, and gas gathering lines. Three new CGFs were installed and five existing CGFs were expanded to add a total of approximately 620 MMcf/d of compression capacity. Additional CGFs within the field are planned for 2017.

In December 2015, there was an initial fire and secondary explosion at the processing facility within the DBM complex. The majority of damage was to the liquid-handling facilities and the amine-treating units at the inlet of the complex. Train II (with capacity of 100 MMcf/d) sustained the most damage of the processing trains and returned to service in December 2016. Train III (with capacity of 200 MMcf/d) experienced minimal damage and returned to full service in May 2016. There was no damage to Trains IV and V (each with a capacity of 200 MMcf/d), which were under construction at the time of the incident. Train IV was commissioned in the second quarter of 2016, and Train V and the high-pressure condensate stabilizer were both commissioned in the fourth quarter of 2016. As of December 31, 2016, the Company had received $33.8 million in cash proceeds from insurers related to the incident, including $16.3 million in proceeds from business interruption insurance claims and $17.5 million in proceeds from property insurance claims.

The DBM complex now includes 700 MMcf/d of cryogenic processing capacity, 1,400 GPM of amine-treating capacity, 18 MBbls/d of high-pressure condensate stabilization, and a rich-gas gathering system, with over 350 miles of high-pressure and low-pressure segments. Construction began on Train VI, a 200-MMcf/d cryogenic facility, in the fourth quarter of 2016, with expected commissioning by the end of 2017.

DJ Basin Anadarko continued to optimize gathering and compression in 2016, which reduced gathering system pressures in the field, enhancing system efficiency and improving the base production profile. Management believes that Anadarko is well-positioned in the DJ basin with its oil and NGLs transportation capacity, which includes transport by pipeline, rail, and truck.

In the second quarter of 2016, the Company commissioned its COSF, capable of handling 100 MBbls/d. The primary benefit of the COSF is the removal of oil product storage tanks at Anadarko's well pad sites, resulting in lower operating expenses, reduced emissions, and further reduced well site surface footprint.

Anadarko has a 20% equity ownership in Saddlehorn Pipeline Company, LLC, which owns 190 MBbls/d of capacity in a shared pipeline. The pipeline was brought into service in the third quarter of 2016 and delivers various grades of oil from the DJ basin to storage facilities in Cushing, Oklahoma.

The Company elected to participate in an expansion of the White Cliffs oil pipeline to increase the total capacity from 150 MBbls/d to approximately 215 MBbls/d. Construction is expected to be completed early in the second quarter of 2017.

Greater Natural Buttes The Chipeta plant's total processing capacity (cryogenic and refrigeration) is approximately 1 Bcf/d with cryogenic processing capacity of 550 MMcf/d. Chipeta's third-party pipeline interconnect has added approximately 100 MMcf/d of natural-gas supply to the plant.

East Texas/North Louisiana The Panola Valley NGL Pipeline expansion was completed in August of 2016. Anadarko has a 15% equity interest in the 248-mile pipeline. The pipeline ends at Mont Belvieu NGL Fractionation facility, where Anadarko has a 25% equity interest in fractionation trains VII and VIII. The trains each have 85 MBbls/d of gross NGLs processing capacity.

Marcellus In the Marcellus shale, the Company efficiently maintained its operated gathering systems with approximately 260 MMcf/d of compression capacity in Lycoming, Clinton, and Centre Counties in Pennsylvania. In December 2016, Anadarko entered into an agreement to sell its operated and nonoperated oil and natural-gas assets and related operated midstream assets to a third-party; the midstream assets owned by WES were excluded from the agreement.

Eagleford In the Eagleford shale, the Company continues to operate oil and gas gathering systems, with a 2016 average gross throughput of 70 MBbls/d of oil and 540 MMcf/d of natural gas. The 200 MMcf/d operated Brasada natural-gas cryogenic processing plant continued steady operations at capacity. In January 2017, Anadarko entered into an agreement to sell its oil and natural-gas assets to a third-party; the midstream assets owned by WES were excluded from the agreement.

The following provides information regarding the Company's midstream assets including gathering, processing, treating, transportation, and produced-water disposal by area (excluding divestitures closed in 2016):

Area	Miles of Pipelines	Total Horsepower	2016 Average Net Throughput (MMcf/d)
DJ basin	5,700	357,500	1,100
Delaware basin	1,600	275,900	500
Greater Natural Buttes	1,300	233,700	900
Marcellus	800	104,200	1,000
Eagleford	900	203,900	500
Other	6,200	245,800	900
Total	16,500	1,421,000	4,900

MARKETING ACTIVITIES

The Company's marketing segment actively manages Anadarko's worldwide oil, natural-gas, and NGLs sales as well as the Company's anticipated LNG sales. In marketing its production, the Company attempts to minimize market-related shut-ins, maximize realized prices, and manage credit-risk exposure. The Company's sales of oil, natural gas, and NGLs are generally made at market prices at the time of sale. The Company also purchases oil, natural gas, and NGLs from third parties, primarily near Anadarko's production areas, to aggregate volumes so the Company is positioned to fully use its transportation, storage, and fractionation capacity; facilitate efforts to maximize prices received; and minimize balancing issues with customers and pipelines during operational disruptions.

The Company sells its products under a variety of contract structures, including indexed, fixed-price, and cost-escalation-based agreements. The Company also engages in limited trading activities for the purpose of generating profits from exposure to changes in market prices of oil, natural gas, and NGLs. The Company does not engage in market-making practices and limits its marketing activities to oil, natural-gas, NGLs, and LNG commodity contracts. The Company's marketing-risk position is typically a net short position (reflecting agreements to sell oil, natural gas, and NGLs in the future for specific prices) that is offset by the Company's natural long position as a producer (reflecting ownership of underlying oil and natural-gas reserves). See *Commodity-Price Risk* under Item 7A of this Form 10-K.

Oil and NGLs Anadarko's oil and NGLs revenues are derived from production in the United States, Algeria, and Ghana. Most of the Company's U.S. oil and NGLs production is sold under contracts with prices based on market indices, adjusted for location, quality, and transportation. Product from Algeria is sold by tanker as Saharan Blend, condensate, refrigerated propane, and refrigerated butane to customers primarily in the Mediterranean area. Oil from Ghana is sold by tanker as Jubilee and TEN Blend Crude Oil to customers around the world. Saharan Blend, Jubilee, and TEN Blend Oil are high-quality crudes that provide refiners with large quantities of premium products such as gasoline, diesel, and jet fuel.

Natural Gas Anadarko markets its U.S. natural-gas production to maximize value and to reduce the inherent risks of physical commodity markets. Anadarko's marketing segment offers supply-assurance and limited risk-management services at competitive prices as well as other services that are tailored to its customers' needs. The Company may also receive a service fee related to the level of reliability and service required by the customer. The Company controls natural-gas firm-transportation capacity that ensures access to downstream markets, which enables the Company to maximize its natural-gas production. This transportation capacity also provides the opportunity to capture incremental value when price differentials between physical locations exist. The Company stores natural gas in contracted storage facilities to minimize operational disruptions to its ongoing operations and to take advantage of seasonal price differentials. Normally, the Company will have forward contracts in place (physical delivery or financial derivative instruments) to sell stored natural gas at a fixed price.

COMPETITION

The oil and gas business is highly competitive in the exploration for and acquisition of reserves and in the gathering and marketing of oil and gas production. The Company's competitors include national oil companies, major integrated oil and gas companies, independent oil and gas companies, individual producers, gas marketers, and major pipeline companies as well as participants in other industries supplying energy and fuel to consumers.

SEGMENT INFORMATION

For additional information on operations by segment, see *Note 25—Segment Information* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K, and for additional information on risk associated with international operations, see *Risk Factors* under Item 1A of this Form 10-K.

EMPLOYEES

The Company had approximately 4,500 employees at December 31, 2016.

REGULATORY AND ENVIRONMENTAL MATTERS

Environmental and Occupational Health and Safety Regulations

Anadarko's business operations are subject to numerous international, provincial, federal, regional, state, tribal, local, and foreign environmental and occupational health and safety laws and regulations. The more significant of these existing environmental and occupational health and safety laws and regulations include the following U.S. laws and regulations, as amended from time to time:

- the U.S. Clean Air Act, which restricts the emission of air pollutants from many sources, imposes various pre-construction, monitoring, and reporting requirements, which the EPA has relied upon as authority for adopting climate change regulatory initiatives relating to greenhouse gas emissions
- the U.S. Federal Water Pollution Control Act, also known as the federal Clean Water Act (CWA), which regulates discharges of pollutants from facilities to state and federal waters and establishes the extent to which waterways are subject to federal jurisdiction and rulemaking as protected waters of the United States
- the U.S. Oil Pollution Act of 1990 (OPA), which subjects owners and operators of vessels, onshore facilities, and pipelines, as well as lessees or permittees of areas in which offshore facilities are located, to liability for removal costs and damages arising from an oil spill in waters of the United States
- U.S. Department of the Interior regulations, which relate to offshore oil and natural-gas operations in U.S. waters and impose obligations for establishing financial assurances for decommissioning activities, liabilities for pollution cleanup costs resulting from operations, and potential liabilities for pollution damages
- the Comprehensive Environmental Response, Compensation and Liability Act of 1980, which imposes liability on generators, transporters, and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur

- the U.S. Resource Conservation and Recovery Act, which governs the generation, treatment, storage, transport, and disposal of solid wastes, including hazardous wastes
- the U.S. Safe Drinking Water Act, which ensures the quality of the nation's public drinking water through adoption of drinking water standards and control over the injection of waste fluids into below-ground formations that may adversely affect drinking water sources
- the U.S. Emergency Planning and Community Right-to-Know Act, which requires facilities to implement a safety hazard communication program and disseminate information to employees, local emergency planning committees, and response departments on toxic chemical uses and inventories
- the U.S. Occupational Safety and Health Act, which establishes workplace standards for the protection of the health and safety of employees, including the implementation of hazard communications programs designed to inform employees about hazardous substances in the workplace, potential harmful effects of these substances, and appropriate control measures
- the Endangered Species Act, which restricts activities that may affect federally identified endangered and threatened species or their habitats through the implementation of operating restrictions or a temporary, seasonal, or permanent ban in affected areas
- the National Environmental Policy Act, which requires federal agencies, including the Department of the Interior, to evaluate major agency actions having the potential to impact the environment and that may require the preparation of environmental assessments and more detailed environmental impact statements that may be made available for public review and comment

These U.S. laws and regulations, as well as state counterparts, generally restrict the level of pollutants emitted to ambient air, discharges to surface water, and disposals or other releases to surface and below-ground soils and ground water. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil, and criminal penalties; the imposition of investigatory, remedial, and corrective action obligations or the incurrence of capital expenditures; the occurrence of delays in the permitting, development, or expansion of projects; and the issuance of injunctions restricting or prohibiting some or all of the Company's activities in a particular area. Moreover, multiple environmental laws provide for citizen suits, which allow environmental organizations to act in the place of the government and sue operators for alleged violations of environmental law. See *Risk Factors* under Item 1A of this Form 10-K for further discussion on hydraulic fracturing; ozone standards; induced seismicity regulatory developments; climate change, including methane or other greenhouse gas emissions; and other regulations relating to environmental protection. The ultimate financial impact arising from environmental laws and regulations is neither clearly known nor determinable as new standards continue to evolve.

Many states where the Company operates also have, or are developing, similar environmental and occupational health and safety laws and regulations governing many of these same types of activities. In addition, many foreign countries where the Company is conducting business also have, or may be developing, regulatory initiatives or analogous controls that regulate Anadarko's environmental-related activities. While the legal requirements imposed under state or foreign law may be similar in form to U.S. laws and regulations, in some cases the actual implementation of these requirements may impose additional, or more stringent, conditions or controls that can significantly alter or delay the permitting, development, or expansion of a project or substantially increase the cost of doing business. In addition, environmental and occupational health and safety laws and regulations, including new or amended legal requirements that may arise in the future to address potential environmental concerns such as air and water impacts, are expected to continue to have an increasing impact on the Company's operations.

The Company has incurred and will continue to incur operating and capital expenditures, some of which may be material, to comply with environmental and occupational health and safety laws and regulations. Historically, the Company's environmental compliance costs have not had a material adverse effect on its results of operations; however, there can be no assurance that such costs will not be material in the future or that such future compliance will not have a material adverse effect on the Company's business and operation results. Although the Company is not fully insured against all environmental and occupational health and safety risks, and the Company's insurance does not cover any penalties or fines that may be issued by a governmental authority, it maintains insurance coverage that it believes is sufficient based on the Company's assessment of insurable risks and consistent with insurance coverage held by other similarly situated industry participants. Nevertheless, it is possible that other developments, such as stricter and more comprehensive environmental and occupational health and safety laws and regulations as well as claims for damages to property or persons resulting from the Company's operations, could result in substantial costs and liabilities, including administrative, civil, and criminal penalties, to Anadarko.

Oil Spill-Response Plan

Domestically, the Company is subject to compliance with the federal Bureau of Safety and Environmental Enforcement (BSEE) regulations, which, among other standards, require every owner or operator of a U.S. offshore lease to prepare and submit for approval an oil spill-response plan prior to conducting any offshore operations. The submitted plan is required to provide a detailed description of actions to be taken in the event of a spill; identify contracted spill-response equipment, materials, and trained personnel; and stipulate the time necessary to deploy identified resources in the event of a spill. The BSEE regulations may be amended, resulting in more stringent requirements as changes to the amount and type of spill-response resources to which an owner or operator must maintain ready access. Accordingly, resources available to the Company may change to satisfy any new regulatory requirements or to adapt to changes in the Company's operations.

Anadarko has in place and maintains Oil Spill-Response Plans (Plans) for the Company's Gulf of Mexico operations. The Plans set forth procedures for a rapid and effective response to spill events that may occur as a result of Anadarko's operations. The Plans are reviewed by the Company at least annually and updated as necessary. Drills are conducted by the Company at least annually to test the effectiveness of the Plans and include the participation of spill-response contractors, representatives of Clean Gulf Associates (CGA, a not-for-profit association of production and pipeline companies operating in the Gulf of Mexico contractually engaged by the Company for such matters), Marine Spill Response Corporation (MSRC), and representatives of relevant governmental agencies. The Plans and any revisions to the Plans must be approved by the BSEE.

As part of the Company's oil spill-response preparedness, and as set forth in the Plans, Anadarko maintains membership in CGA and has an employee representative on the executive committee of CGA. CGA was created to provide a means of effectively staging response equipment and to provide effective spill-response capability for its member companies operating in the Gulf of Mexico. CGA equipment includes, among other things, skimming vessels, barges, boom, and dispersants. CGA has executed a support contract with T&T Marine to coordinate bareboat charters and to provide for expanded response support. T&T Marine is responsible for inspecting, maintaining, storing, and staging CGA equipment. T&T Marine has positioned CGA's equipment and materials in a ready state at various staging areas around the Gulf of Mexico. T&T Marine has service contracts in place with domestic environmental contractors as well as with other companies that provide for support services during the execution of spill-response activities.

Anadarko is also a member of the Marine Preservation Association, which provides full access to the MSRC cooperative. In the event of a spill, MSRC stands ready to mobilize all of its equipment and materials. MSRC has a fleet of dedicated Responder Class Oil Spill Response Vessels (OSRVs), designed and built to recover spilled oil.

MSRC has equipment housed for the Atlantic Region, the Gulf of Mexico Region, the California Region, and the Pacific Northwest Region. Their equipment includes, among other things, skimmers, OSRVs, fast response vessels, barges, storage bladders, work boats, ocean boom, and dispersant.

The Company has also entered into a contractual commitment to access subsea intervention, containment, capture, and shut-in capacity for deepwater exploration wells. Marine Well Containment Company (MWCC) is open to oil and gas operators in the Gulf of Mexico and provides members access to oil spill-response equipment and services on a per-well fee basis. Anadarko has an employee representative on the executive committee of MWCC. MWCC members have access to a containment system that is planned for use in deepwater depths of up to 10,000 feet, with containment capacity of 100 MBbls/d of liquids and flare capability for 200 MMcf/d of natural gas.

Anadarko retains geospatial and satellite imagery services through the MDA Corporation (MDA) to provide coverage over the Company's Gulf of Mexico operations. MDA owns and maintains two radar satellites, which provide all-weather surveillance and imagery available to assist in identifying areas of concern on the surface waters of the Gulf of Mexico. The Company has agreements with Waste Management, Inc. and Clean Harbors to assist in the proper disposal of contaminated and hazardous waste soil and debris. In addition, Anadarko has agreements with several qualified environmental consulting firms for assistance with subsea dispersant applications. The Company also has agreements with TDI-Brooks International for its scientific research vessels to properly monitor the effectiveness of the dispersant application and the health of the ecosystem. The Company also has agreements with Scientific and Environmental Associates, Inc. (SEA) for assistance with surface dispersant applications. SEA is a scientific support consulting firm providing expertise in surface-dispersion applications and efficacy monitoring.

Anadarko has emergency and oil spill-response plans in place for each of its exploration and operational activities around the globe. Each plan is intended to satisfy the requirements of relevant local or national authorities, describes the actions the Company is expected to take in the event of an incident, includes drills conducted by the Company at least annually, and includes reference to external resources that may become necessary in the event of an incident. Included in these external resources is the Company's contract with Oil Spill Response Limited (OSRL), a global emergency and oil spill-response organization headquartered in London. Anadarko also participates in supplementary service provided through OSRL, the Global Dispersant Stockpile (GDS). This additional service provides Anadarko access to dispersant and is available to Anadarko operations worldwide.

OSRL has an aircraft available for dispersant application or equipment transport. OSRL also has a number of active recovery boom systems and a range of booms that can be used for offshore, nearshore, or shoreline responses. In addition, OSRL provides, among other things, a range of communications equipment, safety equipment, transfer pumps, dispersant application systems, temporary storage equipment, power packs and generators, small inflatable vessels, rigid inflatable boats, work boats, and fast response vessels. OSRL also has a wide range of oiled wildlife equipment in conjunction with the Sea Alarm Foundation.

In addition to Anadarko's membership in or access to CGA, MSRC, OSRL, and MWCC, the Company participates in industry-wide task forces, which are currently studying improvements in both gaining access to and controlling blowouts in subsea environments. Two such task forces are the Subsea Well Control and Containment Task Force and the Oil Spill Task Force.

TITLE TO PROPERTIES

As is customary in the oil and gas industry, a preliminary title review is conducted at the time properties believed to be suitable for drilling operations are acquired by the Company. Prior to the commencement of drilling operations, thorough title examinations of the drill site tracts are conducted by third-party attorneys, and curative work is performed with respect to significant defects, if any, before proceeding with operations. Anadarko believes the title to its leasehold properties is good, defensible, and customary with practices in the oil and gas industry, subject to such exceptions that, in the opinion of legal counsel for the Company, do not materially detract from the use of such properties.

Leasehold properties owned by the Company are subject to royalty, overriding royalty, and other outstanding interests customary in the industry. The properties may be subject to burdens such as liens incident to operating agreements, current taxes, development obligations under oil and gas leases and other encumbrances, easements, and restrictions. Anadarko does not believe any of these burdens will materially interfere with its use of these properties.

EXECUTIVE OFFICERS OF THE REGISTRANT

Name	Age at January 31, 2017	Position
R. A. Walker	59	Chairman, President and Chief Executive Officer
Robert G. Gwin	53	Executive Vice President, Finance and Chief Financial Officer
Darrell E. Hollek	59	Executive Vice President, Operations
Mitchell W. Ingram	54	Executive Vice President, Global LNG
Ernest A. Leyendecker	56	Executive Vice President, International and Deepwater Exploration
Robert K. Reeves	59	Executive Vice President, Law and Chief Administrative Officer
Christopher O. Champion	47	Senior Vice President, Chief Accounting Officer and Controller

Mr. Walker was named Chairman of the Board of the Company in May 2013, in addition to the role of Chief Executive Officer and director, both of which he assumed in May 2012, and the role of President, which he assumed in February 2010. He previously served as Chief Operating Officer from March 2009 until his appointment as Chief Executive Officer. He served as Senior Vice President, Finance and Chief Financial Officer from September 2005 until March 2009. From August 2007 until March 2013, he served as director of WGH and served as its Chairman of the Board from August 2007 to September 2009. Mr. Walker served as a director of WGEH from September 2012 until March 2013. Mr. Walker served as a director of Temple-Inland Inc. from November 2008 to February 2012 and a director of CenterPoint Energy, Inc. from April 2010 to April 2015 and has served as a director of BOK Financial Corporation since April 2013, where he is the Chairman of the Risk Committee.

Mr. Gwin was named Executive Vice President, Finance and Chief Financial Officer in May 2013 and previously served as Senior Vice President, Finance and Chief Financial Officer since March 2009 and Senior Vice President since March 2008. He also has served as Chairman of the Board of WGH since October 2009 and as a director since August 2007. Additionally, Mr. Gwin has served as Chairman of the Board of WGEH since September 2012 and served as President of WGH from August 2007 to September 2009 and as Chief Executive Officer of WGH from August 2007 to January 2010. He joined Anadarko in January 2006 as Vice President, Finance and Treasurer and served in that capacity until March 2008. He has served as Chairman of the Board of LyondellBasell Industries N.V. since August 2013 and as a director since May 2011.

Mr. Hollek was named Executive Vice President, Operations in August 2016. Prior to this position, he served as Executive Vice President, U.S. Onshore Exploration and Production since April 2015; Senior Vice President, Deepwater Americas Operations since May 2013; and Vice President, Operations since May 2007. Mr. Hollek joined Anadarko upon the acquisition of Kerr-McGee Corporation in August 2006. He has held positions of increasing responsibility with Anadarko and Kerr-McGee Corporation, where he began his career, including management roles in the Gulf of Mexico; U.S. onshore; and Environmental, Health, Safety and Regulatory. Mr. Hollek has served as a director of WGH and WGEH since May 2015.

Mr. Ingram was named Executive Vice President, Global LNG in November 2015. Prior to joining Anadarko, Mr. Ingram was with BG Group since 2006, where he served as a member of the Executive Committee in the role of Executive Vice President—Technical since March 2015. Previously, he held positions of increasing responsibility with the company's LNG project in Queensland, Australia, where he served as Managing Director of QGC, a BG Group business, since April 2014; as Deputy Managing Director since September 2013; and as Project Director of the Queensland Curtis LNG project since May 2012. From 2006 to May 2012, Mr. Ingram was Asset General Manager of BG Group's Karachaganak interest in Kazakhstan. He joined BG Group after 20 years with Occidental Oil & Gas, where he held several U.K. and international leadership positions in project management, development, and operations.

Mr. Leyendecker was named Executive Vice President, International and Deepwater Exploration in August 2016. Prior to this position, he served as Senior Vice President, International Exploration since April 2015 and Senior Vice President, Gulf of Mexico Exploration since February 2014. Prior to that, he served as Vice President, Gulf of Mexico Exploration since May 2011 and as Vice President of Corporate Planning and Gulf of Mexico Exploration since October 2010. Mr. Leyendecker joined Anadarko upon the acquisition of Kerr-McGee Corporation in August 2006. He has held positions of increasing responsibility with Anadarko and Kerr-McGee Corporation, including Exploration Manager for the Gulf of Mexico and General Manager for Worldwide Exploration, Engineering and Planning. Mr. Leyendecker began his career with Marathon Oil Company prior to pursuing a leadership role with Enterprise Oil Gulf of Mexico, which was acquired by Shell Oil in 2002.

Mr. Reeves was named Executive Vice President, Law and Chief Administrative Officer in September 2015 and previously served as Executive Vice President, General Counsel and Chief Administrative Officer since May 2013 and as Senior Vice President, General Counsel and Chief Administrative Officer since February 2007. He also served as Chief Compliance Officer from July 2012 to May 2013. He served as Corporate Secretary from February 2007 to August 2008. He previously served as Senior Vice President, Corporate Affairs & Law and Chief Governance Officer since 2004. Prior to joining Anadarko, he served as Executive Vice President, Administration and General Counsel of North Sea New Ventures from 2003 to 2004 and as Executive Vice President, General Counsel and Secretary of Ocean Energy, Inc. and its predecessor companies from 1997 to 2003. He served as a director of Key Energy Services, Inc., a publicly traded oilfield services company, from October 2007 to December 2016 and has served as a director of WGH since August 2007 and as a director of WGEH since September 2012.

Mr. Champion was named Senior Vice President, Chief Accounting Officer and Controller in February 2017 and previously served as Vice President, Chief Accounting Officer and Controller since June 2015. Prior to joining Anadarko, Mr. Champion was an Audit Partner with KPMG LLP since October 2003 and served as KPMG's National Audit Leader for Oil and Natural Gas since 2008. He began his career at Arthur Andersen LLP in 1992 before joining KPMG LLP in 2002 as a senior audit manager.

Officers of Anadarko are elected each year at the first meeting of the Board following the annual meeting of stockholders, the next of which is expected to occur on May 10, 2017, and hold office until their successors are duly elected and qualified. There are no family relationships between any directors or executive officers of Anadarko.

Item 1A. Risk Factors

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Unless the context otherwise requires, the terms "Anadarko" and "Company" refer to Anadarko Petroleum Corporation and its consolidated subsidiaries. The Company has made in this Form 10-K, and may from time to time make in other public filings, press releases, and management discussions, forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, concerning the Company's operations, economic performance, and financial condition. These forward-looking statements include, among other things, information concerning future production and reserves, schedules, plans, timing of development, contributions from oil and gas properties, marketing and midstream activities, and also include those statements preceded by, followed by, or that otherwise include the words "may," "could," "believes," "expects," "anticipates," "intends," "estimates," "projects," "target," "goal," "plans," "objective," "should," "would," "will," "potential," "continue," "forecast," "future," "likely," "outlook," or similar expressions or variations on such expressions. For such statements, the Company claims the protection of the safe harbor for forward-looking statements contained in the Private Securities Litigation Reform Act of 1995. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, it can give no assurance that such expectations will be realized. Anadarko undertakes no obligation to publicly update or revise any forward-looking statements whether as a result of new information, future events, or otherwise.

These forward-looking statements involve risk and uncertainties. Important factors that could cause actual results to differ materially from the Company's expectations include, but are not limited to, the following risks and uncertainties:

- *the Company's assumptions about energy markets*
- *production and sales volume levels*
- *levels of oil, natural-gas, and NGLs reserves*
- *operating results*
- *competitive conditions*
- *technology*
- *availability of capital resources, levels of capital expenditures, and other contractual obligations*
- *supply and demand for, the price of, and the commercialization and transporting of oil, natural gas, NGLs, and other products or services*
- *volatility in the commodity-futures market*
- *weather*
- *inflation*
- *availability of goods and services, including unexpected changes in costs*
- *drilling risks*
- *processing volumes and pipeline throughput*
- *general economic conditions, nationally, internationally, or in the jurisdictions in which the Company is, or in the future may be, doing business*
- *the Company's inability to timely obtain or maintain permits or other governmental approvals, including those necessary for drilling and/or development projects*

- *legislative or regulatory changes, including changes relating to hydraulic fracturing; retroactive royalty or production tax regimes; deepwater drilling and permitting regulations; derivatives reform; changes in state, federal, and foreign income taxes; environmental regulation, including regulations related to climate change; environmental risks; and liability under international, provincial, federal, regional, state, tribal, local, and foreign environmental laws and regulations*
- *civil or political unrest or acts of terrorism in a region or country*
- *the creditworthiness and performance of the Company's counterparties, including financial institutions, operating partners, and other parties*
- *volatility in the securities, capital, or credit markets and related risks such as general credit, liquidity, and interest-rate risk*
- *the Company's ability to successfully monetize select assets, repay or refinance its debt, and the impact of changes in the Company's credit ratings*
- *uncertainties associated with acquired properties and businesses*
- *disruptions in international oil and NGLs cargo shipping activities*
- *physical, digital, internal, and external security breaches*
- *supply and demand, technological, political, governmental, and commercial conditions associated with long-term development and production projects in domestic and international locations*
- *other factors discussed below and elsewhere in this Form 10-K, and in the Company's other public filings, press releases, and discussions with Company management*

RISK FACTORS

Oil, natural-gas, and NGLs price volatility, including a substantial or extended decline in the price of these commodities, could adversely affect our financial condition and results of operations.

Prices for oil, natural gas, and NGLs can fluctuate widely. For example, NYMEX West Texas Intermediate oil prices have been volatile and ranged from a high of $107.26 per barrel in June 2014 to a low of $26.21 per barrel in February 2016. Also, NYMEX Henry Hub natural-gas prices have been volatile and ranged from a high of $6.15 per MMBtu in February 2014 to a low of $1.64 per MMBtu in March 2016. Our revenues, operating results, cash flows from operations, capital budget, and future growth rates are highly dependent on the prices we receive for our oil, natural gas, and NGLs. The markets for oil, natural gas, and NGLs have been volatile historically and may continue to be volatile in the future. Factors influencing the prices of oil, natural gas, and NGLs are beyond our control. These factors include, but are not limited to, the following:

- the domestic and worldwide supply of, and demand for, oil, natural gas, and NGLs
- volatility and trading patterns in the commodity-futures markets
- the cost of exploring for, developing, producing, transporting, and marketing oil, natural gas, and NGLs
- the level of global oil and natural-gas inventories
- weather conditions
- the level of U.S. exports of oil, liquefied natural gas, or NGLs
- the ability of the members of OPEC and other producing nations to agree to and maintain production levels
- the worldwide military and political environment, civil and political unrest worldwide, including in Africa and the Middle East, uncertainty or instability resulting from the escalation or additional outbreak of armed hostilities, or acts of terrorism in the United States or elsewhere
- the effect of worldwide energy conservation and environmental protection efforts
- the price and availability of alternative and competing fuels

- the level of foreign imports of oil, natural gas, and NGLs
- domestic and foreign governmental laws, regulations, and taxes
- shareholder activism or activities by non-governmental organizations to restrict the exploration, development, and production of oil and natural gas in order to minimize emissions of carbon dioxide, a greenhouse gas (GHG)
- the proximity to, and capacity of, natural-gas pipelines and other transportation facilities
- general economic conditions worldwide

The long-term effect of these and other factors on the prices of oil, natural gas, and NGLs is uncertain. Prolonged or substantial declines in these commodity prices may have the following effects on our business:

- adversely affect our financial condition, liquidity, ability to finance planned capital expenditures, and results of operations
- reduce the amount of oil, natural gas, and NGLs that we can produce economically
- cause us to delay or postpone some of our capital projects
- reduce our revenues, operating income, or cash flows
- reduce the amounts of our estimated proved oil, natural-gas, and NGLs reserves
- reduce the carrying value of our oil, natural-gas, and midstream properties due to recognizing additional impairments of proved properties, unproved properties, exploration assets, and midstream facilities
- reduce the standardized measure of discounted future net cash flows relating to oil, natural-gas, and NGLs reserves
- limit our access to, or increasing the cost of, sources of capital such as equity and long-term debt
- adversely affect the ability of our partners to fund their working interest capital requirements

We are subject to complex laws and regulations relating to environmental protection that can adversely affect the cost, manner, and feasibility of doing business.

Our operations and properties are subject to numerous international, provincial, federal, regional, state, tribal, local, and foreign laws and regulations governing the release of pollutants or otherwise relating to environmental protection. These laws and regulations govern the following, among other things:

- issuance of permits in connection with exploration, drilling, production, and midstream activities
- drilling activities on certain lands lying within wilderness, wetlands, and other protected areas
- types, quantities, and concentrations of emissions, discharges, and authorized releases
- generation, management, and disposition of waste materials
- offshore oil and natural-gas operations and decommissioning of abandoned facilities
- reclamation and abandonment of wells and facility sites
- remediation of contaminated sites
- protection of endangered species

These laws and regulations may impose substantial liabilities for our failure to comply or for any contamination resulting from our operations, including the assessment of administrative, civil, and criminal penalties; the imposition of investigatory, remedial, and corrective action obligations or the incurrence of capital expenditures; the occurrence of delays in the permitting, development, or expansion of projects; and the issuance of injunctions restricting or prohibiting some or all of our activities in a particular area. Moreover, changes in, or reinterpretations of, environmental laws and regulations governing areas where we operate may negatively impact our operations. Examples of recent proposed and final regulations or other regulatory initiatives include the following:

- *Ground-Level Ozone Standards.* In October 2015, the EPA issued a rule under the Clean Air Act, lowering the National Ambient Air Quality Standard (NAAQS) for ground-level ozone from 75 parts per billion to 70 parts per billion under both the primary and secondary standards to provide requisite protection of public health and welfare, respectively. The EPA is expected to make final geographical attainment designations and issue final non-attainment area requirements pursuant to this NAAQS rule by late 2017, and any designations or requirements that result in reclassification of areas or imposition of more stringent standards may make it more difficult to construct new or modified sources of air pollution in newly designated non-attainment areas. Moreover, states are expected to implement more stringent regulations, which could apply to our operations. Compliance with this rule could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating costs.
- *Reduction of Methane Emissions by the Oil and Gas Industry.* In June 2016, the EPA published a final rule establishing new emissions standards for methane and additional standards for volatile organic compounds from certain new, modified, and reconstructed oil and natural-gas production and natural-gas processing and transmission facilities. The EPA's rule is comprised of New Source Performance Standards, known as Subpart Quad OOOOa, that require certain new, modified, or reconstructed facilities in the oil and natural-gas sector to reduce these methane gas and volatile organic compound emissions. These Subpart Quad OOOOa standards will expand previously issued New Source Performance Standards published by the EPA in 2012, known as Subpart OOOO, by using certain equipment specific emissions control practices with respect to, among other things, hydraulically-fractured oil and natural-gas well completions, fugitive emissions from well sites and compressors, and equipment leaks at natural-gas processing plants and pneumatic pumps. Moreover, in November 2016, the EPA issued a final Information Collection Request seeking information about methane emissions from facilities and operators in the oil and natural-gas industry. The EPA has indicated that it intended to use the information from this request to develop Existing Source Performance Standards for the oil and gas industry. Compliance with this rule could, among other things, require installation of new emission controls on some of our equipment and significantly increase our capital expenditures and operating costs.
- *Induced Seismic Activity Associated with Oilfield Disposal Wells.* We dispose of wastewater generated from oil and natural-gas production operations directly or through the use of third parties. The legal requirements related to the disposal of wastewater in underground injections wells are subject to change based on concerns of the public or governmental authorities regarding such disposal activities. One such concern relates to recent seismic events near injection wells used for the disposal of produced water resulting from oil and natural-gas activities. In response to concerns regarding induced seismicity, regulators in some states have imposed, or are considering imposing, additional requirements in the permitting of produced water disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. For example, Oklahoma issued new rules for wastewater disposal wells in 2014 that imposed certain permitting and operating restrictions and reporting requirements on disposal wells in proximity to faults and also, from time to time, is developing and implementing plans directing certain wells where seismic incidents have occurred to restrict or suspend disposal well operations. The Texas Railroad Commission adopted similar permitting, operating, and reporting rules for disposal wells in 2014. In addition, ongoing class action lawsuits, to which we are not currently a party, allege that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. These developments could result in additional regulation and restrictions on the use of injection wells by us or by commercial disposal well vendors whom we may use from time to time to dispose of wastewater, which could have a material adverse effect on our capital expenditures and operating costs, financial condition, and results of operations.

- *Reduction of Greenhouse Gas Emissions.* The U.S. Congress and the EPA, in addition to some state and regional efforts, have in recent years considered legislation or regulations to reduce emissions of GHGs. These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources. In the absence of federal GHG-limiting legislations, the EPA has determined that GHG emissions present a danger to public health and the environment and has adopted regulations that, among other things, restrict emissions of GHGs under existing provisions of the Clean Air Act and may require the installation of "best available control technology" to limit emissions of GHGs from any new or significantly modified facilities that we may seek to construct in the future if they would otherwise emit large volumes of GHGs together with other criteria pollutants. Also, certain of our operations are subject to EPA rules requiring the monitoring and annual reporting of GHG emissions from specified onshore and offshore production sources. In December 2015, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France that requires member countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. Although this international agreement does not create any binding obligations for nations to limit their GHG emissions, it does include pledges to voluntarily limit or reduce future emissions. Substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce and lower the value of our reserves.

These and other regulatory changes could significantly increase our capital expenditures and operating costs or could result in delays to or limitations on our exploration and production activities, which could have an adverse effect on our financial condition, results of operations, or cash flows. For a description of certain environmental proceedings in which we are involved, see *Legal Proceedings* under Item 3 and *Note 16—Contingencies* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Changes in laws or regulations regarding hydraulic fracturing or other oil and natural-gas operations could increase our costs of doing business, impose additional operating restrictions or delays, and adversely affect our production.

Hydraulic fracturing is an essential and common practice used to stimulate production of oil and natural gas from dense subsurface rock formations such as shales. We routinely apply hydraulic-fracturing techniques in many of our U.S. onshore oil and natural-gas drilling and completion programs. The process involves the injection of water, sand, and additives under pressure into a targeted subsurface formation to fracture the surrounding rock and stimulate production.

Hydraulic fracturing is typically regulated by state oil and natural-gas commissions. However, several federal agencies have also asserted regulatory authority over certain aspects of the process. For example, the EPA issued an effluent limit guidelines final rule in June 2016 prohibiting the discharge of return water recovered from shale natural-gas extraction operations to publicly owned wastewater treatment plants. Also, the Bureau of Land Management (BLM) published a final rule in March 2015 that establishes new or more stringent standards for performing hydraulic fracturing on federal and Indian lands but, in September 2015, the U.S. District Court of Wyoming issued a preliminary injunction barring implementation of this rule, finding that the BLM lacked congressional authority to promulgate the rule. That decision is currently being appealed by the federal government. Also, from time to time, legislation has been introduced, but not enacted, in the U.S. Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In the event that new federal restrictions on the hydraulic-fracturing process are adopted in areas where we operate, we may incur significant additional costs or permitting requirements to comply with such federal requirements, and could experience added delays or curtailment in the pursuit of exploration, development, or production activities.

Certain states in which we operate, including Colorado, Pennsylvania, Louisiana, Texas, and Wyoming, have adopted, and other states are considering adopting, regulations that could impose new or more stringent permitting, disclosure, or other regulatory requirements on hydraulic-fracturing operations, including subsurface water disposal. For example, in January 2016, the Colorado Oil and Gas Conservation Commission approved two new rules that require increased collaborative efforts between oil and natural-gas operators and local governments regarding the siting of large-scale oil and natural-gas facilities in certain urban mitigation areas, and require such operators to pursue certain registrations and/or notifications of local governments. States also could elect to prohibit high volume hydraulic fracturing altogether, following the approach taken by the State of New York in 2015. In addition to state laws, local land use restrictions, such as city ordinances, may restrict drilling in general and/or hydraulic fracturing in particular. For example, several cities in Colorado passed temporary or permanent moratoria on hydraulic fracturing within their respective city limits in 2012 to 2013 but, since that time, local district courts struck down the ordinances for certain of those Colorado cities in 2014, which decisions were upheld by the Colorado Supreme Court in May 2016. Notwithstanding attempts at the local level to prohibit hydraulic fracturing, the opportunity exists for cities to adopt local ordinances allowing hydraulic fracturing activities within their jurisdictions while regulating the time, place, and manner of those activities.

Additionally, certain interest groups in Colorado opposed to oil and natural-gas development generally, and hydraulic fracturing in particular, have from time to time advanced various options for ballot initiatives that, if approved, would allow revisions to the state constitution in a manner that would make such exploration and production activities in the state more difficult in the future. For example, proponents of such initiatives sought to include on the Colorado November 2016 ballot certain amendments that, if approved, could, among other things, authorize local governmental control over oil and natural-gas development in Colorado that could impose more stringent requirements than currently implemented under state law and impose a 2,500-foot mandatory setback between certain oil and natural-gas development facilities and specified occupied structures and areas of interest. These particular amendments failed to gather enough valid signatures to be placed on the November 2016 ballot. However, Amendment 71 was placed on the Colorado 2016 ballot and approved by voters, making it more difficult to place an initiative to amend the constitution on the state ballot. For an initiative to be placed on the state ballot, Amendment 71 requires signatures from 2% of registered voters from each of the state's 35 Senate districts and it must be approved by 55% of the voters. In the event that ballot initiatives, local or state restrictions, or prohibitions are adopted and result in more stringent limitations on the production and development of oil and natural gas in areas where we conduct operations, we may incur significant costs to comply with such requirements or may experience delays or curtailment in the permitting or pursuit of exploration, development, or production activities. In addition, we could possibly be limited or precluded in the drilling of wells or in the amounts that we are ultimately able to produce from our reserves. Such compliance costs and delays, curtailments, limitations, or prohibitions could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity.

In addition to asserting regulatory authority, a number of federal entities have reviewed various environmental issues associated with hydraulic fracturing. For example, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources "under some circumstances," noting that the following hydraulic fracturing "water cycle" activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits.

Our debt and other financial commitments may limit our financial and operating flexibility.

Our total debt was $15.3 billion at December 31, 2016. We also have various commitments for leases, drilling contracts, derivative contracts, firm transportation, and purchase obligations for services and products. Our financial commitments could have important consequences to our business, including, but not limited to, the following:

- increasing our vulnerability to general adverse economic and industry conditions
- limiting our ability to fund future working capital and capital expenditures, to engage in future acquisitions or development activities, or to otherwise fully realize the value of our assets and opportunities because of the need to dedicate a substantial portion of our cash flows from operations to payments on our debt or to comply with any restrictive terms of our debt
- limiting our flexibility in planning for, or reacting to, changes in the industry in which we operate
- placing us at a competitive disadvantage compared to our competitors that have less debt and/or fewer financial commitments

Additionally, the credit agreements governing our Five-Year Facility and our 364-Day Facility contain a number of customary covenants, including a financial covenant requiring maintenance of a consolidated indebtedness to total capitalization ratio of no greater than 65% (excluding the effect of non-cash write-downs), and limitations on certain secured indebtedness, sale-and-leaseback transactions, and mergers and other fundamental changes. Our ability to meet such covenants may be affected by events beyond our control.

A downgrade in our credit rating could negatively impact our cost of and ability to access capital.

As of December 31, 2016, our long-term debt was rated "BBB" with a stable outlook by S&P and Fitch. Our long-term debt was rated "Ba1" with a stable outlook by Moody's, which is below investment grade. As of the time of filing this Form 10-K, no additional changes in our credit rating have occurred and we are not aware of any current plans of S&P, Fitch, or Moody's to revise their respective credit ratings on our long-term debt. Any downgrade in our credit ratings could negatively impact our cost of capital and could also adversely affect our ability to effectively execute aspects of our strategy or to raise debt in the public debt markets.

As a result of Moody's below-investment-grade rating of our long-term debt in February 2016, we became more likely to be required to post collateral in the form of letters of credit or cash as financial assurance of our performance under certain contractual arrangements such as pipeline transportation contracts and oil and gas sales contracts. The amount of letters of credit or cash provided as assurance of our performance under these types of contractual arrangements with respect to credit-risk-related contingent features was $274 million at December 31, 2016, and zero at December 31, 2015. Additionally, certain of these arrangements contain financial assurances language that may, under certain circumstances, permit our counterparties to request additional collateral.

Furthermore, as a result of Moody's rating, the credit thresholds with certain derivative counterparties were reduced and in some cases eliminated, which required us to increase the amount of collateral posted with derivative counterparties when our net trading position is a liability in excess of the contractual threshold. No counterparties have requested termination or full settlement of derivative positions. The aggregate fair value of derivative instruments with credit-risk-related contingent features for which a net liability position existed was $1.4 billion (net of $117 million of collateral) at December 31, 2016, and $1.3 billion (net of $58 million of collateral) at December 31, 2015. For additional information, see *Note 9—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Additionally, in February 2016, Moody's downgraded our commercial paper program credit rating, which eliminated our access to the commercial paper market.

Our proved reserves are estimates. Any material inaccuracies in our reserves estimates or assumptions underlying our reserves estimates could cause the quantities and net present value of our reserves to be overstated or understated.

There are numerous uncertainties inherent in estimating quantities of proved reserves, including many factors beyond our control that could cause the quantities and net present value of our reserves to be overstated or understated. The reserves information included or incorporated by reference in this Form 10-K represents estimates prepared by our internal engineers. The procedures and methods for estimating the reserves by our internal engineers were reviewed by independent petroleum consultants; however, no reserves audit was conducted by these consultants. Estimation of reserves is not an exact science. Estimates of economically recoverable oil, natural-gas, and NGLs reserves and of future net cash flows depend on a number of variable factors and assumptions, any of which may cause actual results to vary considerably from these estimates. These factors and assumptions may include, but are not limited to, the following:

- estimated future production from an area is consistent with historical production from similar producing areas
- assumed effects of regulation by governmental agencies and court rulings
- assumptions concerning future oil, natural-gas, and NGLs prices, future operating costs, and capital expenditures
- estimates of future severance and excise taxes, workover costs, and remedial costs

Estimates of reserves based on risk of recovery and estimates of expected future net cash flows prepared by different engineers, or by the same engineers at different times, may vary substantially. Actual production, revenues, and expenditures with respect to our reserves will likely vary from estimates, and the variance may be material. The discounted cash flows included in this Form 10-K should not be construed as the fair value of the estimated oil, natural-gas, and NGLs reserves attributable to our properties. The estimated discounted future net cash flows from proved reserves are based on the average beginning-of-month prices during the 12-month period for the respective year. Actual future prices and costs may differ materially from the SEC regulation-compliant prices used for purposes of estimating future discounted net cash flows from proved reserves. Therefore, reserves quantities will change when actual prices increase or decrease.

Failure to replace reserves may negatively affect our business.

Our future success depends on our ability to find, develop, or acquire additional oil and natural-gas reserves that are economically recoverable. Our proved reserves generally decline when reserves are produced, unless we conduct successful exploration or development activities, acquire properties containing proved reserves, or both. We may be unable to find, develop, or acquire additional reserves on an economic basis. Furthermore, if oil and natural-gas prices increase, our costs for finding or acquiring additional reserves could also increase.

Our domestic operations are subject to governmental risks that may impact our operations.

Our domestic operations have been, and at times in the future may be, affected by political developments and are subject to complex provincial, federal, regional, state, tribal, local, and other laws and regulations such as restrictions on production, permitting, changes in taxes, deductions, royalties and other amounts payable to governments or governmental agencies, price or gathering-rate controls, and hydraulic fracturing, induced seismicity, and environmental protection regulations. To the extent our domestic operations are offshore, we must also comply with requirements focused on oil and natural-gas exploration and production activities in coastal and outer continental shelf (OCS) waters. To conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals, and certificates from various provincial, federal, regional, state, tribal, and local governmental authorities. We may incur substantial costs to maintain compliance with these existing laws and regulations. Our costs of compliance may increase if existing laws, including environmental and tax laws and regulations, are revised or reinterpreted, or if new laws and regulations become applicable to our operations such as the adoption of government-payment-transparency regulations. In past years, legislation has been proposed that would, if enacted into law, make significant changes to U.S. tax laws, including to certain key U.S. federal income tax provisions currently available to oil and natural-gas companies. Such legislative changes have included, but not been limited to, the elimination of current deductions for intangible drilling and development costs, and the elimination of the deduction for certain domestic production activities. The U.S. Congress could consider, and could include, some or all of these proposals as part of tax reform legislation to accompany lower federal income tax rates. Moreover, other more general features of tax-reform legislation, including changes to the rules related to cost recovery and foreign tax credits, and to the deductibility of interest expense, may be developed that also would change the taxation of oil and natural-gas companies. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could take effect. The passage of any legislation as a result of these proposals or any similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that currently are available with respect to oil and natural-gas development, or increase costs, and any such changes could have an adverse effect on the Company's financial position, results of operations, and cash flows.

Future economic, business, or industry conditions may have a material adverse effect on our results of operations, liquidity, and financial condition.

During the last few years, concerns over inflation, potential default on U.S. debt, energy costs, geopolitical issues, the availability and cost of credit, and uncertainties with regard to European sovereign debt, have each contributed at various times to increased economic uncertainty and diminished expectations for the global economy. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. Continued concerns could cause demand for petroleum products to diminish or stagnate, which could impact the price at which we can sell our oil, natural gas, and NGLs and impede the execution of long-term sales agreements or prices thereunder which are the basis for future LNG production; affect the ability of our vendors, suppliers, and customers to continue operations; and ultimately adversely impact our results of operations, liquidity, and financial condition.

We are vulnerable to risks associated with our offshore operations that could negatively impact our operations and financial results.

We conduct offshore operations in the Gulf of Mexico, Ghana, Mozambique, Colombia, Côte d'Ivoire, and other countries. Our operations and financial results could be significantly impacted by conditions in some of these areas and are also vulnerable to certain unique risks associated with operating offshore, including those relating to the following:

- hurricanes and other adverse weather conditions
- geological complexities and water depths associated with such operations
- limited number of partners available to participate in projects
- oilfield service costs and availability
- compliance with environmental, safety, and other laws and regulations
- terrorist attacks such as piracy
- remediation and other costs and regulatory changes resulting from oil spills or releases of hazardous materials
- failure of equipment or facilities
- response capabilities for personnel, equipment, or environmental incidents

In addition, we conduct much of our exploration in deep waters (greater than 1,000 feet) where operations, support services, and decommissioning activities are more difficult and costly than in shallower waters. The deep waters in the Gulf of Mexico, as well as international deepwater locations, lack the physical and oilfield service infrastructure present in shallower waters. As a result, deepwater operations may require significant time between a discovery and the time that we can market our production, thereby increasing the risk involved with these operations.

Additional domestic and international deepwater drilling laws, regulations, and other restrictions; delays in the processing and approval of drilling permits and exploration, development, oil spill-response, and decommissioning plans; and other related developments may have a material adverse effect on our business, financial condition, or results of operations.

In recent years, the Bureau of Ocean Energy Management (BOEM) and the BSEE, agencies of the U.S. Department of the Interior, have imposed more stringent permitting procedures and regulatory safety and performance requirements for new wells to be drilled in federal waters. For example, in 2016, BSEE finalized rule-making entitled Oil and Sulfur Operations on the Outer Continental Shelf — Blowout Prevention Systems and Well Control which focuses on well blowout preventer systems and well control with respect to operations on the OCS. Compliance with these more stringent regulatory requirements and with existing environmental and oil spill regulations, together with any uncertainties or inconsistencies in decisions and rulings by governmental agencies, delays in the processing and approval of drilling permits or exploration, development, oil spill-response and decommissioning plans, and possible additional regulatory initiatives could result in difficult and more costly actions and adversely affect or delay new drilling and ongoing development efforts.

In addition, new regulatory initiatives may be adopted or enforced by the BOEM or the BSEE in the future that could result in additional costs, delays, restrictions, or obligations with respect to oil and natural-gas exploration and production operations conducted offshore. For example, in April 2016, the BOEM published a proposed rule that would update existing air-emissions requirements relating to offshore oil and natural-gas activity on federal OCS waters including in the Central Gulf of Mexico. In addition, in September 2016, the BOEM issued a Notice to Lessees and Operators that would bolster supplemental bonding procedures for the decommissioning of offshore wells, platforms, pipelines, and other facilities. These regulatory actions, or any new rules, regulations, or legal initiatives could delay or disrupt our operations, increase the risk of expired leases due to the time required to develop new technology, result in increased supplemental bonding and costs, and limit activities in certain areas, or cause us to incur penalties, fines, or shut-in production at one or more of our facilities or result in the suspension or cancellation of leases. Moreover, under existing BOEM and BSEE rules relating to assignment of offshore leases and other legal interests on the OCS, assignors of such interests may be held jointly and severally liable for decommissioning of OCS facilities existing at the time the assignment was approved by the BOEM, in the event that the assignee is unable or unwilling to conduct required decommissioning. In the event that we, in the role of assignor, receive orders from the BSEE to decommission OCS facilities that one of our assignees of offshore facilities is unwilling or unable to perform, we could incur costs to perform those decommissioning obligations, which costs could be material.

Also, if material spill events were to occur in the future, the United States or other countries where such an event were to occur could elect to issue directives to temporarily cease drilling activities and, in any event, may from time to time issue further safety and environmental laws and regulations regarding offshore oil and gas exploration and development. We cannot predict with any certainty the full impact of any new laws, regulations, or legal initiatives on our drilling operations or on the cost or availability of insurance to cover the risks associated with such operations. The overall costs to implement and complete any such spill response activities or any decommissioning obligations could exceed estimated accruals, insurance limits, or supplemental bonding amounts, which could result in the incurrence of additional costs to complete.

Further, the deepwater Gulf of Mexico (as well as international deepwater locations) lacks the degree of physical and oilfield service infrastructure present in shallower waters. Therefore, despite our oil spill-response capabilities, it may be difficult for us to quickly or effectively execute any contingency plans related to potential material events in the future.

The matters described above, individually or in the aggregate, could have a material adverse effect on our business, prospects, results of operations, financial condition, and liquidity.

We operate in foreign countries and are subject to political, economic, and other uncertainties.

We have operations outside the United States, including in Algeria, Ghana, Mozambique, Colombia, Côte d'Ivoire, and other countries. As a result, we face political and economic risks and other uncertainties with respect to our international operations. These risks may include the following, among other things:

- loss of revenue, property, and equipment or delays in operations as a result of hazards such as expropriation, war, piracy, acts of terrorism, insurrection, civil unrest, and other political risks, including tension and confrontations among political parties
- transparency issues in general and, more specifically, the U.S. Foreign Corrupt Practices Act, the U.K. Bribery Act, and other anti-corruption compliance laws and issues
- increases in taxes and governmental royalties
- unilateral renegotiation of contracts by governmental entities
- redefinition of international boundaries or boundary disputes
- difficulties enforcing our rights against a governmental agency because of the doctrine of sovereign immunity and foreign sovereignty over international operations
- changes in laws and policies governing operations of foreign-based companies
- foreign-exchange restrictions
- international monetary fluctuations and changes in the relative value of the U.S. dollar as compared to the currencies of other countries in which we conduct business

For example, Ghana and Côte d'Ivoire are engaged in a dispute regarding the international maritime boundary between the two countries. As a result, Côte d'Ivoire claims to be entitled to the maritime area, which covers a portion of the Deepwater Tano Block where the TEN complex is located. In the event Côte d'Ivoire is successful in its maritime border claims, our operations in Ghana could be materially impacted.

Outbreaks of civil and political unrest and acts of terrorism have occurred in countries in Europe, Africa, and the Middle East, including countries close to or where we conduct operations. Continued or escalated civil and political unrest and acts of terrorism in the countries in which we operate could result in our curtailing operations. In the event that countries in which we operate experience civil or political unrest or acts of terrorism, especially in events where such unrest leads to an unseating of the established government, our operations in such countries could be materially impaired.

Our international operations may also be adversely affected, directly or indirectly, by laws, policies, and regulations of the United States affecting foreign trade and taxation, including U.S. trade sanctions.

Realization of any of the factors listed above could materially and adversely affect our financial condition, results of operations, or cash flows.

The high cost or unavailability of drilling rigs, equipment, supplies, personnel, and other oilfield services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget, which could have a material adverse effect on our business, financial condition, or results of operations.

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies, or qualified personnel. The cost for such items may increase as a result of a variety of factors beyond our control, such as increases in the cost of electricity, steel, and other raw materials that we and our vendors rely upon; increased demand for labor, services, and materials as drilling activity increases; and increased taxes. Decreased levels of drilling activity in the oil and gas industry in recent periods have led to declining costs of some drilling rigs, equipment, supplies, or qualified personnel. However, if commodity prices rise, such costs may rise faster than increases in our revenue and their availability to us may be limited. Additionally, these services may not be available on commercially reasonable terms. The high cost or unavailability of drilling rigs, equipment, supplies, personnel, and other oilfield services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget, which could have a material adverse effect on our business, financial condition, or results of operations.

Deterioration in the credit or equity markets could adversely affect us.

We have exposure to different counterparties. For example, we have entered into transactions with counterparties in the financial services industry, including commercial banks, investment banks, insurance companies, investment funds, and other institutions. These transactions expose us to credit risk in the event of default by our counterparty. Deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill existing obligations to us and their willingness to enter into future transactions with us. We have exposure to these financial institutions through our derivative transactions. In addition, if any lender under our credit facilities is unable to fund its commitment, our liquidity will be reduced by an amount up to the aggregate amount of such lender's commitment under our credit facilities. Moreover, to the extent that purchasers of our production rely on access to the credit or equity markets to fund their operations, there is a risk that those purchasers could default in their contractual obligations to us if such purchasers were unable to access the credit or equity markets for an extended period of time.

We are not insured against all of the operating risks to which our business is exposed.

Our business is subject to all of the operating risks normally associated with the exploration for and production, gathering, processing, and transportation of oil and natural gas, including blowouts; cratering and fire; environmental hazards such as natural-gas leaks, oil spills, pipeline and vessel ruptures, and releases of chemicals or other hazardous substances, any of which could result in damage to, or destruction of, oil and natural-gas wells or formations, production facilities, and other property; pollution or other environmental damage; and injury to persons. For protection against financial loss resulting from these operating hazards, we maintain insurance coverage, including insurance coverage for certain physical damage, blowout/loss of control of a well, comprehensive general liability, aviation liability, and worker's compensation and employer's liability. However, our insurance coverage may not be sufficient to cover us against 100% of potential losses arising as a result of the foregoing and for certain risks, such as political risk, business interruption, war, terrorism, and piracy, for which we have limited or no coverage. In addition, we are not insured against all risks in all aspects of our business such as hurricanes. The occurrence of a significant event against which we are not fully insured could have a material adverse effect on our financial condition, results of operations, or cash flows.

Our commodity-price risk-management and trading activities may prevent us from fully benefiting from price increases and may expose us to other risks.

To the extent that we engage in commodity-price risk-management activities to protect our cash flows from commodity-price declines, we may be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, our commodity-price risk-management and trading activities may expose us to the risk of financial loss in certain circumstances, including instances in which the following occur:

- our production is less than the notional volumes
- a widening of price basis differentials occurs between delivery points for our production and the delivery point assumed in the derivative arrangement
- the counterparties to our hedging or other price-risk management contracts fail to perform under those arrangements
- a sudden unexpected event materially impacts oil, natural-gas, or NGLs prices

The enactment of derivatives legislation, and the promulgation of regulations pursuant thereto, could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity-price, interest-rate, and other risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), enacted in 2010, requires the Commodity Futures Trading Commission (CFTC) and the SEC to promulgate rules and regulations establishing federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market, including swap clearing and trade execution requirements. While many rules and regulations have been promulgated and are already in effect, other rules and regulations, including the proposed position limits rule, remain to be finalized or effectuated, and therefore, the impact of those rules and regulations on us is uncertain at this time.

The Dodd-Frank Act, and the rules promulgated thereunder, could (i) significantly increase the cost, or decrease the liquidity, of energy-related derivatives we use to hedge against commodity-price fluctuations (including through requirements to post collateral), (ii) materially alter the terms of derivative contracts, and (iii) reduce the availability and use of derivatives to protect against risks we encounter. If we reduce our use of derivatives as a result of the Dodd-Frank Act and applicable rules and regulations, our cash flow may become more volatile and less predictable, which could adversely affect our ability to plan for and fund capital expenditures. In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, those transactions may become subject to such regulations. At this time, the impact of such regulations is not clear.

Material differences between the estimated and actual timing of critical events may affect the completion of and commencement of production from development projects.

We are involved in several large development projects and the completion of those projects may be delayed beyond our anticipated completion dates. Key factors that may affect the timing and outcome of such projects include the following:

- project approvals and funding by joint-venture partners
- timely issuance of permits and licenses by governmental agencies or legislative and other governmental approvals
- weather conditions
- availability of qualified personnel
- civil and political environment of, and existing infrastructure in, the country or region in which the project is located
- manufacturing and delivery schedules of critical equipment
- commercial arrangements for pipelines and related equipment to transport and market hydrocarbons

Delays and differences between estimated and actual timing of critical events may affect the forward-looking statements related to large development projects and could have a material adverse effect on our results of operations.

The oil and gas exploration and production industry is very competitive, and some of our exploration and production competitors have greater financial and other resources than we do.

The oil and gas business is highly competitive in the search for and acquisition of reserves and in the gathering and marketing of oil and gas production. Our competitors include national oil companies, major integrated oil and gas companies, independent oil and gas companies, individual producers, gas marketers, and major pipeline companies as well as participants in other industries supplying energy and fuel to consumers. Some of our competitors may have greater and more diverse resources on which to draw than we do. If we are not successful in our competition for oil and gas reserves or in our marketing of production, our financial condition and results of operations may be adversely affected.

Our drilling activities may not encounter commercially productive oil or natural-gas reservoirs.

Drilling for oil and natural gas involves numerous risks, including the risk that we will not encounter commercially productive oil or natural-gas reservoirs. Drilling operations may be curtailed, delayed, or canceled as a result of a variety of factors, including the following:

- unexpected drilling conditions
- pressure or irregularities in formations
- equipment failures or accidents
- fires, explosions, blowouts, and surface cratering
- marine risks such as capsizing, collisions, and hurricanes
- difficulty identifying and retaining qualified personnel
- title problems
- other adverse weather conditions
- lack of availability or delays in the delivery of technology, equipment, or resources for operations

As of December 31, 2016, we had $1.7 billion in suspended well and associated non-producing leasehold costs related to 11 U.S. offshore and international exploration projects, which includes approximately $800 million related to our Shenandoah project in the Gulf of Mexico. Certain of these future exploration and appraisal drilling activities may not be successful and, if unsuccessful, could result in a material adverse effect on our future results of operations and financial condition. While all drilling, whether developmental or exploratory, involves these risks, exploratory drilling involves greater risks of dry holes or failure to find commercial quantities of hydrocarbons. Because of the percentage of our capital budget devoted to higher-risk exploratory projects, it is likely that we will continue to experience significant exploration and dry hole expenses.

We have limited influence over the activities on properties we do not operate.

Other companies operate some of the properties in which we have an interest. We have limited ability to influence the operation or future development of these nonoperated properties or the amount or timing of capital expenditures that we are required to fund with respect to them. Our dependence on the operator and other working-interest owners for these projects and our limited ability to influence the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital, lead to unexpected future costs, or adversely affect the timing of activities.

Our ability to sell our oil, natural-gas, and NGLs production could be materially harmed if we fail to obtain adequate services such as transportation.

The marketability of our production depends in part on the availability, proximity, and capacity of pipeline facilities and tanker transportation. If any pipelines or tankers become unavailable, we would, to the extent possible, be required to find a suitable alternative to transport the oil, natural gas, and NGLs, which could increase our costs and/or reduce the revenues we might obtain from the sale of the oil and gas.

Our results of operations could be adversely affected by goodwill impairments.

As a result of mergers and acquisitions, we had approximately $5.0 billion of goodwill on our Consolidated Balance Sheet at December 31, 2016. Goodwill must be tested at least annually for impairment, and more frequently when circumstances indicate likely impairment. Goodwill is considered impaired to the extent that its carrying amount exceeds its implied fair value. Various factors could reduce the fair value of a reporting unit such as our inability to replace the value of our depleting asset base, difficulty or potential delays in obtaining drilling permits, or other adverse events such as lower oil and natural-gas prices, which could lead to an impairment of goodwill. An impairment of goodwill could have a substantial negative effect on our reported earnings.

Risks related to acquisitions may adversely affect our business, financial condition, and results of operations.

Any acquisition, including the recent GOM Acquisition, involves potential risks, including, among other things:

- the validity of our assumptions about, among other things, reserves, estimated production, revenues, capital expenditures, operating expenses, and costs
- the assumption of environmental, decommissioning, and other liabilities, and losses or costs for which we are not indemnified or for which our indemnity is inadequate
- a failure to attain or maintain compliance with environmental, safety, and other governmental regulations

If any of these risks materialize, the benefits of such acquisition may not be fully realized, if at all, and our business, financial condition, and results of operations could be negatively impacted.

Our business could be negatively affected by security threats, including cybersecurity threats, and other disruptions.

As an oil and gas producer, we face various security threats, including cybersecurity threats such as attempts to gain unauthorized access to sensitive information or to render data or systems unusable; threats to the security of our facilities and infrastructure or those of third parties such as processing plants and pipelines; and threats from terrorist acts. Our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities, and infrastructure may result in increased costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. Cybersecurity attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software, attempts to gain unauthorized access to data and systems, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data, which could have an adverse effect on our reputation, financial condition, results of operations, or cash flows.

While we have experienced cybersecurity attacks, we have not suffered any material losses relating to such attacks; however, there is no assurance that we will not suffer such losses in the future. In addition, as cybersecurity threats continue to evolve, we may be required to expend additional resources to continue to modify or enhance our protective measures or to investigate or remediate any cybersecurity vulnerabilities.

Provisions in our corporate documents and Delaware law could delay or prevent a change of control of Anadarko, even if that change would be beneficial to our stockholders.

Our restated certificate of incorporation and by-laws contain provisions that may make a change of control of Anadarko difficult, even if it may be beneficial to our stockholders, including provisions governing the nomination and removal of directors, the prohibition of stockholder action by written consent and regulation of stockholders' ability to bring matters for action before annual stockholder meetings, and the authorization given to our Board of Directors to issue and set the terms of preferred stock.

In addition, Section 203 of the Delaware General Corporation Law imposes restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock.

We may reduce or cease to pay dividends on our common stock.

We can provide no assurance that we will continue to pay dividends at the current rate or at all. In response to the commodity-price environment, in February 2016, the Company decreased the quarterly dividend from $0.27 per share to $0.05 per share. The amount of cash dividends, if any, to be paid in the future is determined by our Board of Directors based on our financial condition, results of operations, cash flows, levels of capital and exploration expenditures, future business prospects, expected liquidity needs, and other matters that our Board of Directors deems relevant.

The loss of key members of our management team, or difficulty attracting and retaining experienced technical personnel, could reduce our competitiveness and prospects for future success.

The successful implementation of our strategies and handling of other issues integral to our future success will depend, in part, on our experienced management team. The loss of key members of our management team could have an adverse effect on our business. We do not carry key man insurance. Our exploratory drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced explorationists, engineers, and other professionals. Competition for such professionals could be intense. If we cannot retain our technical personnel or attract additional experienced technical personnel, our ability to compete could be harmed.

Item 1B. Unresolved Staff Comments

None.

Item 3. Legal Proceedings

The Company is a defendant in a number of lawsuits and is involved in governmental proceedings and regulatory controls arising in the ordinary course of business, including personal injury and death claims; title disputes; tax disputes; royalty claims; contract claims; contamination claims relating to oil and gas exploration, development, production, transportation, and processing; and environmental claims, including claims involving assets owned by acquired companies and claims involving assets previously sold to third parties and no longer a part of the Company's current operations. Anadarko is also subject to various environmental-remediation and reclamation obligations arising from federal, state, tribal, and local laws and regulations. While the ultimate outcome and impact on the Company cannot be predicted with certainty, after consideration of recorded expense and liability accruals, management believes that the resolution of pending proceedings will not have a material adverse effect on the Company's financial condition, results of operations, or cash flows.

WGR Operating, LP, a wholly owned subsidiary of the Company, is currently in negotiations with the EPA with respect to alleged noncompliance with the leak detection and repair requirements of the Clean Air Act at its Granger, Wyoming facilities. Although management cannot predict the outcome of settlement discussions, it is likely a resolution of this matter will result in a fine or penalty in excess of $100,000.

Anadarko E&P Onshore LLC, a wholly owned subsidiary of the Company, is currently in negotiations with the Pennsylvania Fish and Boat Commission and the Pennsylvania Department of Environmental Protection concerning enforcement over a produced water release in Pennsylvania in 2015. Although management cannot predict the outcome of settlement discussions, it is likely a resolution of these matters will result in a fine or penalty in excess of $100,000.

Kerr-McGee Oil and Gas Onshore, LP, a wholly owned subsidiary of the Company, is currently in negotiations with the State of Colorado's Department of Public Health and Environment with respect to alleged noncompliance with the Colorado Air Quality Control Commission's Regulations. Although management cannot predict the outcome of settlement discussions, it is likely a resolution of this matter will result in a fine or penalty in excess of $100,000.

See *Note 16—Contingencies* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K, which is incorporated herein by reference, for a discussion of material legal proceedings to which the Company is a party.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

MARKET INFORMATION, HOLDERS, AND DIVIDENDS

At January 31, 2017, there were approximately 10,280 holders of record of Anadarko common stock. The common stock of Anadarko is traded on the New York Stock Exchange. The following shows information regarding the market price of, and dividends declared and paid on, the Company's common stock by quarter for 2016 and 2015:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2016				
Market Price				
High	**$ 50.39**	**$ 57.00**	**$ 63.84**	**$ 73.33**
Low	**$ 28.16**	**$ 43.52**	**$ 50.23**	**$ 58.59**
Dividends	**$ 0.05**	**$ 0.05**	**$ 0.05**	**$ 0.05**
2015				
Market Price				
High	$ 90.10	$ 95.94	$ 78.70	$ 73.87
Low	$ 73.82	$ 77.75	$ 58.10	$ 44.50
Dividends	$ 0.27	$ 0.27	$ 0.27	$ 0.27

The amount of future common stock dividends will depend on earnings, financial condition, capital requirements, the effect a dividend payment would have on the Company's compliance with its financial covenants, and other factors and will be determined by the Board of Directors on a quarterly basis. For additional information, see *Liquidity and Capital Resources—Financing Activities—Common Stock Dividends* and *Distributions to Noncontrolling Interest Owners* under Item 7 of this Form 10-K.

SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

The following sets forth information with respect to the equity compensation plans available to directors, officers, and employees of the Company at December 31, 2016:

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants, and rights	(b) Weighted-average exercise price of outstanding options, warrants, and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column(a))
Equity compensation plans approved by security holders	6,620,252	$ 76.10	33,927,750
Equity compensation plans not approved by security holders	—	—	—
Total	6,620,252	$ 76.10	33,927,750

PURCHASES OF EQUITY SECURITIES BY THE ISSUER AND AFFILIATED PERSONS

The following sets forth information with respect to repurchases made by the Company of its shares of common stock during the fourth quarter of 2016:

Period	Total number of shares purchased [(1)]	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs	Approximate dollar value of shares that may yet be purchased under the plans or programs
October 1-31, 2016	29,815	$ 61.63	—	
November 1-30, 2016	46,041	$ 59.09	—	
December 1-31, 2016	13,067	$ 69.44	—	
Total	88,923	$ 61.46	—	$ —

(1) During the fourth quarter of 2016, all purchased shares related to stock received by the Company for the payment of withholding taxes due on employee share issuances under share-based compensation plans.

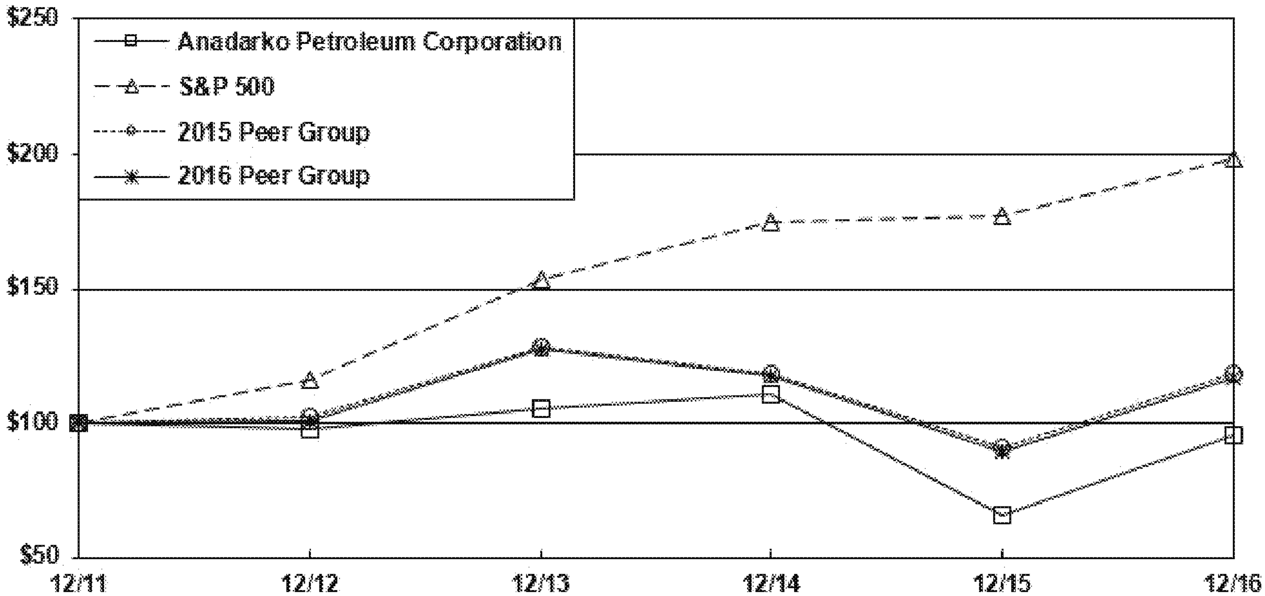
For additional information, see *Note 21—Share-Based Compensation* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

PERFORMANCE GRAPH

The following performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filing.

The following graph compares the cumulative five-year total return to stockholders of Anadarko's common stock relative to the cumulative total returns of the S&P 500 index and two peer groups. The 11 companies included in the 2016 peer group are Apache Corporation; Chesapeake Energy Corporation; Chevron Corporation; ConocoPhillips; Devon Energy Corporation; EOG Resources, Inc.; Hess Corporation; Marathon Oil Corporation; Noble Energy, Inc.; Occidental Petroleum Corporation; and Pioneer Natural Resources Company. The 11 companies included in the 2015 peer group are Apache Corporation; Chevron Corporation; ConocoPhillips; Devon Energy Corporation; EOG Resources, Inc.; Hess Corporation; Marathon Oil Corporation; Murphy Oil Corporation; Noble Energy, Inc.; Occidental Petroleum Corporation; and Pioneer Natural Resources Company. Murphy Oil Corporation was removed from the peer group due to it being low in relative size after spinning off its retail marketing business and was replaced with Chesapeake Energy Corporation.

Comparison of 5-Year Cumulative Total Return Among Anadarko Petroleum Corporation, the S&P 500 Index, the 2016 Peer Group, and the 2015 Peer Group



An investment of $100 (with reinvestment of all dividends) is assumed to have been made in the Company's common stock, in the S&P 500 Index, and in the 2016 and 2015 Peer Groups on December 31, 2011, and its relative performance is tracked through December 31, 2016.

Fiscal Year Ended December 31	2011	2012	2013	2014	2015	**2016**
Anadarko Petroleum Corporation	$100.00	$ 97.84	$105.07	$110.47	$ 66.07	**$ 95.18**
S&P 500	100.00	116.00	153.58	174.60	177.01	**198.18**
2016 Peer Group	100.00	101.98	128.16	118.26	90.77	**118.40**
2015 Peer Group	100.00	101.04	127.81	117.70	89.44	**116.70**

Item 6. Selected Financial Data

millions except per-share amounts	**2016**	2015	2014	2013	2012
	Summary Financial Information [1]				
Sales Revenues	**$ 8,447**	$ 9,486	$ 16,375	$ 14,867	$ 13,307
Gains (Losses) on Divestitures and Other, net	**(578)**	(788)	2,095	(286)	104
Total Revenues and Other	**7,869**	8,698	18,470	14,581	13,411
Other Operating (Income) Expense					
Algeria Exceptional Profits Tax Settlement	**—**	—	—	33	(1,797)
Operating Income (Loss)	**(2,599)**	(8,809)	5,403	3,333	3,727
Tronox-related Contingent Loss	**—**	5	4,360	850	(250)
Income (Loss)	**(2,808)**	(6,812)	(1,563)	941	2,445
Net Income (Loss) Attributable to Common Stockholders	**(3,071)**	(6,692)	(1,750)	801	2,391
Per Common Share (amounts attributable to common stockholders)					
Net Income (Loss)—Basic	**$ (5.90)**	$ (13.18)	$ (3.47)	$ 1.58	$ 4.76
Net Income (Loss)—Diluted	**$ (5.90)**	$ (13.18)	$ (3.47)	$ 1.58	$ 4.74
Dividends	**$ 0.20**	$ 1.08	$ 0.99	$ 0.54	$ 0.36
Average Number of Common Shares Outstanding—Basic	**522**	508	506	502	500
Average Number of Common Shares Outstanding—Diluted	**522**	508	506	505	502
Cash Provided by (Used in) Operating Activities	**3,000**	(1,877)	8,466	8,888	8,339
Capital Expenditures	**$ 3,314**	$ 5,888	$ 9,256	$ 8,523	$ 7,311
Short-term Debt [4]	**$ 42**	$ 32	$ —	$ 500	$ —
Long-term Debt [2] [4]	**15,281**	15,636	15,004	12,984	13,180
Total Debt [4]	**$ 15,323**	$ 15,668	$ 15,004	$ 13,484	$ 13,180
Total Stockholders' Equity	**12,212**	12,819	19,725	21,857	20,629
Total Assets	**$ 45,564**	$ 46,414	$ 60,967	$ 55,421	$ 52,261
Annual Sales Volumes					
Oil (MMBbls)	**116**	116	106	91	86
Natural Gas (Bcf)	**766**	852	945	968	913
Natural Gas Liquids (MMBbls)	**46**	47	44	33	30
Total (MMBOE) [3]	**290**	305	308	285	268
Average Daily Sales Volumes					
Oil (MBbls/d)	**316**	317	292	248	233
Natural Gas (MMcf/d)	**2,093**	2,334	2,589	2,652	2,495
Natural Gas Liquids (MBbls/d)	**128**	130	119	91	83
Total (MBOE/d)	**793**	836	843	781	732
Proved Reserves					
Oil Reserves (MMBbls)	**702**	713	929	851	767
Natural-gas Reserves (Tcf)	**4.4**	6.0	8.7	9.2	8.3
Natural-gas Liquids Reserves (MMBbls)	**283**	340	479	407	405
Total Proved Reserves (MMBOE)	**1,722**	2,057	2,858	2,792	2,560
Number of Employees	**4,500**	5,800	6,100	5,700	5,200

(1) Consolidated for Anadarko and its subsidiaries. Certain amounts for prior years have been reclassified to conform to the current presentation.

(2) Includes WGP debt of $28 million at December 31, 2016. Includes WES debt of $3.1 billion at December 31, 2016, $2.7 billion at December 31, 2015, $2.4 billion at December 31, 2014, $1.4 billion at December 31, 2013, and $1.2 billion at December 31, 2012.

(3) Natural gas is converted to equivalent barrels at the rate of 6,000 cubic feet of gas per barrel.

(4) As a result of adopting ASU 2015-03, *Interest - Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* and ASU 2015-15, *Interest - Imputation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements*, the Company reduced other current assets and short-term debt by $1 million and reduced other assets and long-term debt by $82 million in 2015, $88 million in 2014, $81 million in 2013, and $89 million in 2012. See *Note 1 - Summary of Significant Accounting Policies* in the *Notes to the Consolidated Financial Statements* under Item 8 of this Form 10-K.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion should be read together with the *Consolidated Financial Statements* and the *Notes to Consolidated Financial Statements*, which are included in this Form 10-K in Item 8, and the information set forth in *Risk Factors* under Item 1A.

MANAGEMENT OVERVIEW

In 2016, Anadarko optimized and further concentrated its portfolio on higher-return, oil-levered opportunities in areas where it possesses both scale and competitive advantages, namely the Delaware and DJ basins in the U.S. onshore and deepwater Gulf of Mexico. As part of this effort, the Company closed or announced divestitures of numerous non-core U.S. onshore assets primarily located in South Texas, West Texas, East Texas/Louisiana, Wyoming, Kansas, and Pennsylvania while completing the GOM Acquisition. The GOM Acquisition expanded Anadarko's operated infrastructure and substantial tie-back inventory, more than doubled the Company's ownership interest in the Lucius development to approximately 49%, and doubled its net production from the Gulf of Mexico to more than 160 MBOE/d, more than 80% of which is comprised of oil. The acquired assets are expected to generate substantial cash flow over the next five years at current strip prices, allowing the Company to increase investment and growth in the Delaware and DJ basins. The Company expects to end the first quarter of 2017 with 14 operated drilling rigs in the Delaware basin and 6 operated drilling rigs in the DJ basin, which compares to 7 operated drilling rigs in the Delaware basin and 1 operated drilling rig in the DJ basin at the end of the third quarter of 2016. Recent successful exploration activity with the Warrior discovery and Phobos appraisal wells, which each provide tie-back opportunities, further demonstrate the value of the Company's operated infrastructure and its hub-and-spoke capabilities in the deepwater Gulf of Mexico.

As with any oil and natural-gas exploration and production company, Anadarko's revenues, operating results, cash flows from operations, capital spending, and future growth rates are highly influenced by commodity prices, which affect the value the Company receives from its sales of oil, natural gas, and NGLs. Supply and demand have been slow to return to a sustained equilibrium following the decline in commodity prices in 2015 and 2016, although the November 2016 OPEC decision to cut production is expected to help accelerate the drawdown of global oil inventories. Recognizing the lower commodity-price environment, Anadarko enhanced its liquidity position by retiring and/or redeeming near-term debt maturities, primarily with proceeds from debt issued in the first quarter of 2016; executing the aforementioned monetization program; reducing capital expenditures by approximately 50% (excluding WES) relative to the prior year; enhancing operational efficiencies; and improving its cost structure through a dividend decrease and workforce reduction program. Anadarko believes that the actions taken in 2016 have positioned it well with the necessary financial flexibility to fund the Company's current and long-term operations.

Significant 2016 operating and financial activities include the following:

Total Company

- The Company's oil sales volumes were flat year over year, while the Company's 2016 capital budget (excluding WES) was reduced by nearly 50%.
- The Company's overall sales-volume product mix increased to 56% liquids in 2016 compared to 53% in 2015.
- The Company improved its cost structure by approximately $800 million annually after 2016 through a dividend decrease and a workforce reduction program.
- The Company closed approximately $4 billion of monetizations in 2016, including asset divestitures in the U.S. onshore, the sale of Anadarko's interest in Springfield Pipeline LLC to WES, the sale of a portion of the Company's common units in WGP to the public, and the Company's conveyance of a limited-term nonparticipating royalty interest in certain of its coal and trona leases to a third party.

U.S. Onshore

- In December 2016, the Company entered into an agreement to sell its Marcellus oil and gas assets and certain related midstream assets for approximately $1.2 billion. In January 2017, the Company entered into an agreement to sell its Eagleford oil and gas assets for approximately $2.3 billion. These transactions are expected to close in the first quarter of 2017.
- Total sales volumes in the DJ basin averaged 244 MBOE/d, representing a 9% or 20 MBOE/d increase from 2015.
- Total sales volumes in the Delaware basin averaged 45 MBOE/d, representing a 41% or 13 MBOE/d increase from 2015. Oil sales volumes in the Delaware basin increased 8 MBbls/d, representing a 50% increase from 2015.
- The Company increased rig activity in the Delaware and DJ basins during the year, ending 2016 with nine operated rigs in the Delaware basin and five operated rigs in the DJ basin, compared to six rigs in the Delaware basin and two in the DJ basin in the first quarter of 2016.

Gulf of Mexico

- In December 2016, the Company acquired oil and gas assets in the Gulf of Mexico for $1.8 billion net of purchase-price adjustments, expanding its operated infrastructure and substantial tie-back inventory.
- Oil sales volumes averaged 65 MBbls/d, representing a 23% increase from 2015, primarily due to new wells coming online in 2016 at Caesar/Tonga and K2, first oil from Heidelberg, and an increased flow rate at Lucius.

International

- The TEN development project (19% nonoperated participating interest) in Ghana achieved first oil in the third quarter of 2016.
- In 2016, the operator at the Jubilee field in Ghana announced that damage to the FPSO turret bearing had occurred. As a result, new production and offtake procedures were implemented and the partners agreed to a long-term solution to convert the FPSO to a permanently-moored facility. Interim mooring of the vessel commenced in the fourth quarter of 2016 and is expected to be completed during the first quarter of 2017. Final decisions and approvals will be sought for the long-term turret system solution in the first half of 2017. It is anticipated that a facility shutdown of up to 12 weeks may be required in the second half of 2017. The partnership is actively seeking optimization solutions to minimize the duration of any shutdown period.
- The Company's Algeria operations achieved the highest production rates since 2009 due to the completion of the increased water-handling project at the Ourhoud facility and obtaining approval of a new reservoir development plan for the El Merk fields allowing for higher plateau rates.
- During the fourth quarter of 2016, the Development Plan for the initial two-train onshore LNG project in Mozambique was submitted to the Government of Mozambique.

Financial

- The Company generated $3.0 billion of cash flow from operations and ended 2016 with $3.2 billion of cash.
- During the second quarter of 2016, the Company used proceeds from a March 2016 public offering of Senior Notes totaling $3.0 billion due 2021, 2026, and 2046 to redeem its $1.750 billion Senior Notes due 2016 and to purchase and retire $1.25 billion of its Senior Notes due 2017. In the fourth quarter of 2016, Anadarko redeemed its remaining $750 million Senior Notes due 2017.
- During the third quarter of 2016, the Company completed a public offering of 40.5 million shares of its common stock for net proceeds of $2.16 billion. Net proceeds were primarily used to fund the GOM Acquisition.

FINANCIAL RESULTS

millions except per-share amounts	**2016**	2015	2014
Oil, natural-gas, and NGLs sales	**$ 7,153**	$ 8,260	$ 15,169
Gathering, processing, and marketing sales	**1,294**	1,226	1,206
Gains (losses) on divestitures and other, net	**(578)**	(788)	2,095
Revenues and other	**$ 7,869**	$ 8,698	$ 18,470
Costs and expenses	**10,468**	17,507	13,067
Other (income) expense	**1,230**	880	5,349
Income tax expense (benefit)	**(1,021)**	(2,877)	1,617
Net income (loss) attributable to common stockholders	**$ (3,071)**	$ (6,692)	$ (1,750)
Net income (loss) per common share attributable to common stockholders—diluted	**$ (5.90)**	$ (13.18)	$ (3.47)
Average number of common shares outstanding—diluted	**522**	508	506

The following discussion pertains to Anadarko's results of operations, financial condition, and changes in financial condition. Any increases or decreases "for the year ended December 31, 2016," refer to the comparison of the year ended December 31, 2016, to the year ended December 31, 2015. Similarly, any increases or decreases "for the year ended December 31, 2015," refer to the comparison of the year ended December 31, 2015, to the year ended December 31, 2014.

Revenues and Sales Volumes

millions	Oil	Natural Gas	NGLs	Total
2015 sales revenues	$ 5,420	$ 2,007	$ 833	$ 8,260
Changes associated with prices	**(745)**	**(241)**	**95**	**(891)**
Changes associated with sales volumes	**(7)**	**(202)**	**(7)**	**(216)**
2016 sales revenues	**$ 4,668**	**$ 1,564**	**$ 921**	**$ 7,153**
Increase/(decrease) vs. 2015	**(14)%**	**(22)%**	**11 %**	**(13)%**
2014 sales revenues	$ 9,748	$ 3,849	$ 1,572	$ 15,169
Changes associated with prices	(5,189)	(1,462)	(871)	(7,522)
Changes associated with sales volumes	861	(380)	132	613
2015 sales revenues	$ 5,420	$ 2,007	$ 833	$ 8,260
Increase/(decrease) vs. 2014	(44)%	(48)%	(47)%	(46)%

The above table illustrates the effects of the lower commodity-price environment in 2015 and 2016 as decreases in commodity prices were the main driver of the Company's sales revenue decreases year over year.

Over the past few years, the Company's investment focus has shifted towards high-margin oil assets and the Company has divested several non-core assets resulting in decreased natural-gas volumes in 2015 and 2016.

The following provides Anadarko's sales volumes for the years ended December 31:

	2016	Inc (Dec) vs. 2015	2015	Inc (Dec) vs. 2014	2014
Barrels of Oil Equivalent					
(MMBOE except percentages)					
United States	**257**	(5)%	272	(1)%	275
International	**33**	(1)	33	(1)	33
Total barrels of oil equivalent	**290**	(5)	305	(1)	308
Barrels of Oil Equivalent per Day					
(MBOE/d except percentages)					
United States	**704**	(5)%	745	(1)%	751
International	**89**	(1)	91	(1)	92
Total barrels of oil equivalent per day	**793**	(5)	836	(1)	843

Sales volumes represent production volumes adjusted for changes in commodity inventories and natural-gas production volumes provided to satisfy a commitment established in conjunction with the Jubilee development plan in Ghana. Anadarko employs marketing strategies to minimize market-related shut-ins, maximize realized prices, and manage credit-risk exposure. For additional information, see *Note 9—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K. Production of oil, natural gas, and NGLs is usually not affected by seasonal swings in demand.

Oil Sales Revenues, Average Prices, and Volumes

	2016	Inc (Dec) vs. 2015	2015	Inc (Dec) vs. 2014	2014
Oil sales revenues (millions)	**$ 4,668**	(14)%	$ 5,420	(44)%	$ 9,748
United States					
Sales volumes—MMBbls	**85**	1 %	85	14 %	74
MBbls/d	**233**	1	232	14	203
Price per barrel	**$ 39.06**	(13)	$ 45.00	(49)	$ 87.99
International					
Sales volumes—MMBbls	**31**	(2)%	31	(4)%	32
MBbls/d	**83**	(2)	85	(4)	89
Price per barrel	**$ 43.93**	(15)	$ 51.68	(48)	$ 99.79
Total					
Sales volumes—MMBbls	**116**	— %	116	9 %	106
MBbls/d	**316**	—	317	9	292
Price per barrel	**$ 40.34**	(14)	$ 46.79	(49)	$ 91.58

The following summarizes primary drivers for the change in oil sales revenues:

millions	**Change in Revenues**	**Due to Change in Prices**	**Due to Change in Volumes**
2016 vs. 2015	$ (752)	$ (745)	$ (7)
2015 vs. 2014	(4,328)	(5,189)	861

Oil Prices

The average oil price Anadarko received decreased from late 2014 through late 2016 primarily due to continued high global petroleum inventories and strong supply growth from OPEC. Oil prices began to improve in late 2016 following OPEC's decision to curb production for the first six months of 2017.

Oil Sales Volumes

2016 vs. 2015 The Company's oil sales volumes remained relatively flat.

U.S. Onshore

- Sales volumes for the Delaware basin increased by 8 MBbls/d primarily due to continued field development.
- Sales volumes for the DJ basin decreased by 6 MBbls/d primarily due to reduced capital activity.
- Sales volumes decreased by 7 MBbls/d primarily due to the sale of certain EOR assets in 2015 and the sale of certain Wyoming and East Texas/Louisiana assets in 2016.

Gulf of Mexico

- Sales volumes increased by 12 MBbls/d, primarily due to new wells coming online at K2 and Caesar/Tonga in the first half of 2016, an increased flow rate at Lucius, and the achievement of first oil at Heidelberg in January 2016.

International

- Sales volumes for Ghana decreased by 7 MBbls/d primarily due to downtime during 2016 to address new production and offtake procedures resulting from issues associated with the Jubilee field FPSO turret bearing. Shuttle tankers are conducting offtakes until the facility is permanently moored. The decrease in volumes at Jubilee were partially offset by TEN coming online late in the third quarter.

2015 vs. 2014 The Company's oil sales volumes increased by 25 MBbls/d primarily due to the following:

U.S. Onshore

- Sales volumes for the DJ basin increased by 21 MBbls/d primarily due to continued horizontal drilling activity.
- Sales volumes for the Delaware basin increased by 3 MBbls/d primarily due to wells brought online as a result of additional infrastructure and continued drilling.
- Sales volumes decreased by 10 MBbls/d primarily due to the sale of certain EOR assets in 2015.

Gulf of Mexico

- Sales volumes for Lucius increased by 14 MBbls/d primarily due to the achievement of first oil in the first quarter of 2015.

Natural-Gas Sales Revenues, Volumes, and Average Prices

	2016	Inc (Dec) vs. 2015	2015	Inc (Dec) vs. 2014	2014
Natural-gas sales revenues (millions)	**$ 1,564**	(22)%	$ 2,007	(48)%	$ 3,849
United States					
Sales volumes—Bcf	**766**	(10)%	852	(10)%	945
MMcf/d	**2,093**	(10)	2,334	(10)	2,589
Price per Mcf	**$ 2.04**	(14)	$ 2.36	(42)	$ 4.07

The following summarizes primary drivers for the change in natural-gas sales revenues:

millions	Change in Revenues	Due to Change in Prices	Due to Change in Volumes
2016 vs 2015	$ (443)	$ (241)	$ (202)
2015 vs 2014	(1,842)	(1,462)	(380)

Natural-Gas Prices

The average natural-gas price Anadarko received decreased from 2014 through 2016 primarily due to strong year over year production growth in the northeast United States coupled with lower weather-driven residential and commercial demand in 2015, which led to high gas storage levels in 2016. High storage levels persisted through the majority of 2016.

Natural-Gas Sales Volumes

2016 vs. 2015 The Company's natural-gas sales volumes decreased by 241 MMcf/d primarily due to the following:

U.S. Onshore

- Sales volumes for the DJ basin increased by 98 MMcf/d primarily due to improved performance.
- Sales volumes for the Delaware basin increased by 18 MMcf/d primarily due to continued field development.
- Sales volumes decreased by 290 MMcf/d primarily due to the sale of certain coalbed methane properties and certain U.S. onshore properties and related midstream assets in East Texas in 2015 and the sale of certain Wyoming and East Texas/Louisiana assets in 2016.

Gulf of Mexico

- Sales volumes decreased by 61 MMcf/d primarily as a result of the last producing well at Independence Hub going off line in December 2015.

2015 vs. 2014 The Company's natural-gas sales volumes decreased by 255 MMcf/d primarily due to the following:

U.S. Onshore

- Sales volumes for Marcellus shale decreased by 118 MMcf/d primarily due to production modulation and third-party infrastructure downtime.
- Sales volumes for Greater Natural Buttes decreased by 89 MMcf/d primarily due to production modulation.
- Sales volumes for the DJ basin increased by 144 MMcf/d primarily due to continued horizontal drilling activity.
- Sales volumes decreased by 137 MMcf/d primarily due to the sale of certain U.S. onshore properties and related midstream assets in East Texas and the sale of certain coalbed methane properties in 2015.

Gulf of Mexico

- Sales volumes decreased by 60 MMcf/d primarily due to natural production decline at Independence Hub.

Natural-Gas Liquids Sales Revenues, Volumes, and Average Prices

	2016	Inc (Dec) vs. 2015	2015	Inc (Dec) vs. 2014	2014
Natural-gas liquids sales revenues (millions)	**$ 921**	11 %	$ 833	(47)%	$ 1,572
United States					
Sales volumes—MMBbls	**44**	(1)%	45	6 %	43
MBbls/d	**122**	(1)	124	6	116
Price per barrel	**$ 19.32**	13	$ 17.03	(52)	$ 35.48
International					
Sales volumes—MMBbls	**2**	10 %	2	91 %	1
MBbls/d	**6**	10	6	91	3
Price per barrel	**$ 25.63**	(14)	$ 29.85	(47)	$ 56.16
Total					
Sales volumes—MMBbls	**46**	(1)%	47	8 %	44
MBbls/d	**128**	(1)	130	8	119
Price per barrel	**$ 19.64**	12	$ 17.61	(51)	$ 36.01

The following summarizes primary drivers for the change in NGLs sales revenues:

millions	**Change in Revenues**	**Due to Change in Prices**	**Due to Change in Volumes**
2016 vs. 2015	$ 88	$ 95	$ (7)
2015 vs. 2014	(739)	(871)	132

NGLs Prices

The average NGLs price Anadarko received decreased from 2014 to 2015, primarily due to the related decline in oil prices over the same period. Prices began recovering in 2016 due to overall higher demand, resulting in an increase in NGLs prices in 2016.

NGLs Sales Volumes

NGLs sales represent revenues from the sale of products derived from the processing of Anadarko's natural-gas production. The Company's NGLs sales volumes remained relatively flat from 2014 through 2016.

Gathering, Processing, and Marketing

millions except percentages	**2016**	Inc (Dec) vs. 2015	2015	Inc (Dec) vs. 2014	2014
Gathering, processing, and marketing sales	**$ 1,294**	6%	$ 1,226	2%	$ 1,206
Gathering, processing, and marketing expense	**1,087**	3	1,054	2	1,030
Total gathering, processing, and marketing, net	**$ 207**	20	$ 172	(2)	$ 176

Gathering and processing sales includes revenue from the sale of NGLs and remaining residue gas extracted from natural gas purchased from third parties and processed by Anadarko as well as fee revenue earned by providing gathering, processing, compression, and treating services to third parties. Marketing sales include the margin earned from purchasing and selling third-party oil and natural gas. Gathering, processing, and marketing expense includes the cost of third-party natural gas purchased and processed by Anadarko as well as other operating and transportation expenses related to the Company's costs to perform gathering, processing, and marketing activities.

2016 vs. 2015 Gathering, processing, and marketing, net increased by $35 million. This increase primarily related to higher gas and NGLs throughput volumes at the DJ basin and DBM complex.

2015 vs. 2014 Gathering, processing, and marketing, net remained relatively flat.

Gains (Losses) on Divestitures and Other, net

millions except percentages	**2016**	Inc (Dec) vs. 2015	2015	Inc (Dec) vs. 2014	2014
Gains (losses) on divestitures, net	**$ (757)**	26%	$ (1,022)	(154)%	$ 1,891
Other	**179**	(24)	234	15	204
Total gains (losses) on divestitures and other, net	**$ (578)**	27	$ (788)	(138)	$ 2,095

Gains (losses) on divestitures and other, net includes gains (losses) on divestitures and other operating revenues, including hard-minerals royalties, earnings from equity investments, and other revenues.

During 2016 and 2015, Anadarko divested of certain non-core U.S. onshore assets and recognized net losses of $757 million in 2016 and $1.0 billion in 2015.

In 2014, the Company recognized net gains of $1.9 billion primarily associated with the divestitures of a 10% working interest in Offshore Area 1 in Mozambique and the Company's Chinese subsidiary.

See *Note 3—Acquisitions, Divestitures, and Assets Held for Sale* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information.

Costs and Expenses

The following provides Anadarko's total costs and expenses for the years ended December 31:

millions	**2016**	2015	2014
Oil and gas operating	**$ 811**	$ 1,014	$ 1,171
Oil and gas transportation	**1,002**	1,117	1,116
Exploration	**946**	2,644	1,639
Gathering, processing, and marketing	**1,087**	1,054	1,030
General and administrative	**1,440**	1,176	1,316
DD&A	**4,301**	4,603	4,550
Production, property, and other taxes	**536**	553	1,244
Impairments	**227**	5,075	836
Other operating expense	**118**	271	165
Total	**$ 10,468**	$ 17,507	$ 13,067

Oil and Gas Operating and Transportation Expenses

	2016	Inc (Dec) vs. 2015	2015	Inc (Dec) vs. 2014	2014
Oil and gas operating (millions)	**$ 811**	(20)%	$ 1,014	(13)%	$ 1,171
Oil and gas operating—per BOE	**2.79**	(16)	3.32	(13)	3.81
Oil and gas transportation (millions)	**1,002**	(10)	1,117	—	1,116
Oil and gas transportation—per BOE	**3.46**	(5)	3.66	1	3.63

Oil and Gas Operating Expenses

2016 vs. 2015 Oil and gas operating expenses decreased by $203 million primarily due to the following:

- lower expenses of $112 million as a result of divestitures
- lower workover costs of $28 million in the Gulf of Mexico and the U.S. onshore
- lower surface maintenance costs of $16 million in the U.S. onshore and the Gulf of Mexico

The related costs per BOE decreased by $0.53 primarily due to continued cost reduction initiatives and efficiencies across the Company's U.S. operating areas.

2015 vs. 2014 Oil and gas operating expenses decreased by $157 million primarily due to the following:

- lower expenses of $73 million as a result of divestitures
- lower workover costs of $49 million as a result of reduced activity primarily in the U.S. onshore
- lower surface maintenance expenses of $21 million primarily in the U.S. onshore

The related costs per BOE decreased by $0.49 due to cost reduction initiatives and efficiencies across the Company's U.S. operating areas.

Oil and Gas Transportation Expenses

2016 vs. 2015 Oil and gas transportation expenses decreased by $115 million due to overall lower gas sales volumes. Oil and gas transportation expenses per BOE decreased by $0.20 primarily due to lower costs as a result of lower gas sales volumes.

2015 vs. 2014 Oil and gas transportation expenses and expenses per BOE were relatively flat.

Exploration Expense

millions	**2016**	2015	2014
Dry hole expense	**$ 397**	$ 1,052	$ 762
Impairments of unproved properties	**216**	1,215	483
Geological and geophysical expense	**121**	168	168
Exploration overhead and other	**212**	209	226
Total exploration expense	**$ 946**	$ 2,644	$ 1,639

Dry Hole Expense

2016

- The Company expensed suspended exploratory well costs of $231 million related to certain wells in the Gulf of Mexico and $92 million related to certain wells in Mozambique. See *Note 6—Suspended Exploratory Well Costs* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.
- The Company expensed $39 million for a well in Côte d'Ivoire that finished drilling in the third quarter of 2016 and encountered noncommercial quantities of hydrocarbons.
- Anadarko expensed $35 million due to unsuccessful drilling activities primarily associated with Gulf of Mexico and U.S. onshore properties.

2015

- The Company expensed suspended exploratory well costs of $746 million in 2015, primarily related to Brazil where the Company does not expect to have substantive exploration and development activities for the foreseeable future given the current oil-price environment and other considerations.
- The Company expensed $306 million due to unsuccessful drilling activities in 2015 primarily in Colombia and the Gulf of Mexico.

2014

- Anadarko expensed $762 million due to unsuccessful drilling activities in 2014 associated with wells in the Gulf of Mexico, U.S. onshore, and Mozambique.

Impairments of Unproved Properties

2016

- The Company recognized a $72 million impairment of unproved properties in the Gulf of Mexico and $92 million for unproved international properties primarily in Brazil and Tunisia due to the Company's current intentions to not pursue future exploration activities.

2015

- The Company recognized a $935 million impairment of unproved Greater Natural Buttes properties and a $66 million impairment of an unproved Gulf of Mexico property as a result of lower commodity prices.
- The Company recognized a $109 million impairment of unproved Utica properties resulting from an assignment of mineral interests in settlement of a legal matter.

2014

- The Company recognized impairments of $302 million primarily related to lower oil prices, a reduction of reserves, and the expiration of certain leases in the Gulf of Mexico.
- The Company recognized impairments of $50 million due to the decision not to pursue further drilling in Sierra Leone.
- The Company recognized impairments of $38 million in 2014 as a result of changes in the Company's drilling plans for certain U.S. onshore oil and gas properties.

General and Administrative Expenses

millions except percentages	**2016**	Inc (Dec) vs. 2015	2015	Inc (Dec) vs. 2014	2014
General and administrative	**$ 1,440**	22%	$ 1,176	(11)%	$ 1,316

2016 vs. 2015 G&A for the year ended December 31, 2016, included $389 million of charges associated with a workforce reduction program initiated in March 2016. Excluding the workforce reduction expenses, G&A decreased by $125 million primarily due to lower employee-related expenses resulting from the workforce reduction. See *Note 17—Restructuring Charges* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

2015 vs. 2014 G&A expense decreased by $140 million primarily due to lower bonus plan expense and lower legal fees, partially offset by increased benefit plan expense.

Depreciation, Depletion, and Amortization

millions except percentages	**2016**	Inc (Dec) vs. 2015	2015	Inc (Dec) vs. 2014	2014
DD&A	**$ 4,301**	(7)%	$ 4,603	1%	$ 4,550

2016 vs. 2015 DD&A expense decreased by $302 million, primarily due to the following:

- lower carrying value for U.S. onshore and midstream properties as a result of 2015 asset impairments and divestitures in 2015 and 2016
- lower 2016 sales volumes associated with U.S. onshore properties

2015 vs. 2014 DD&A expense remained relatively flat.

Impairments

The Company recognized the following impairments for the years ended December 31:

millions	**2016**	2015	2014
Oil and gas exploration and production			
U.S. onshore properties	**$ 28**	$ 3,684	$ 545
Gulf of Mexico properties	**27**	349	276
Cost-method investment	**59**	3	3
Midstream	**73**	1,039	12
Other	**40**	—	—
Total impairments (1)	**$ 227**	$ 5,075	$ 836

(1) In 2015, $3.0 billion of oil and gas exploration and production impairments and $482 million of midstream asset impairments related to Greater Natural Buttes.

Potential for Future Impairments At December 31, 2016, the Company's estimates of undiscounted future cash flows attributable to a certain international asset group with a net book value of approximately $1.3 billion indicated that the carrying amount was expected to be recovered; however, this asset group may be at risk for impairment if the estimates of future cash flows decline. The Company estimates that a 10% decline in oil prices (with all other assumptions unchanged) could result in a non-cash impairment in excess of $550 million for the asset group. It is also reasonably possible that significant declines in commodity prices, further changes to the Company's drilling plans in response to lower prices, or increases in drilling or operating costs could result in other additional impairments.

See *Note 5—Impairments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information on impairments and *Risk Factors* under Item 1A of this Form 10-K for further discussion on the risks associated with oil, natural-gas, and NGLs prices.

Other (Income) Expense

The following provides Anadarko's other (income) expense for the years ended December 31:

millions	**2016**	2015	2014
Interest expense	**$ 890**	$ 825	$ 772
Loss on early extinguishment of debt (1)	**155**	—	—
(Gains) losses on derivatives, net (2)	**286**	(99)	197
Other (income) expense, net	**(101)**	149	20
Tronox-related contingent loss (3)	**—**	5	4,360
Total	**$ 1,230**	$ 880	$ 5,349

(1) See *Note 11—Debt and Interest Expense* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for information on early extinguishment of debt.

(2) See *Note 9—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

(3) See *Note 16—Contingencies —Tronox Litigation* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Interest Expense

millions	**2016**	2015	2014
Current debt, long-term debt, and other	**$ 1,022**	$ 989	$ 973
Capitalized interest	**(132)**	(164)	(201)
Total interest expense	**$ 890**	$ 825	$ 772

2016 vs. 2015 Interest expense increased by $65 million.

- Interest expense on debt and other increased by $33 million primarily related to WES debt issuances in 2015 and 2016 and interest expense related to the Ghana TEN capital lease commencement in the third quarter of 2016.
- Capitalized interest decreased by $32 million primarily due to lower construction-in-progress balances for long-term capital projects in Brazil and the completion of the Heidelberg development, partially offset by higher construction in progress balances related to projects in Mozambique, Côte d'Ivoire, and Colombia.

2015 vs. 2014 Interest expense increased by $53 million.

- Interest expense on debt and other increased by $16 million primarily due to higher debt outstanding during 2015, partially offset by decreased debt amortization costs for the $5.0 Billion Facility.
- Capitalized interest decreased by $37 million primarily due to the completion of the Lucius development and lower construction-in-progress balances for long-term capital projects in Brazil, partially offset by higher construction-in-progress balances for long-term capital projects primarily in Ghana.

Income Tax Expense (Benefit)

millions except percentages	**2016**	2015	2014
Income tax expense (benefit)	**$ (1,021)**	$ (2,877)	$ 1,617
Income (loss) before income taxes	**(3,829)**	(9,689)	54
Effective tax rate	**27%**	30%	2,994%

The Company's effective tax rate is impacted each year by the relative pre-tax income earned by the Company's operations in the U.S., Algeria, and the rest of the world. Additionally, state income taxes (net of federal income tax benefit), non-deductible Algerian exceptional profits tax for Algerian income tax purposes, net changes in uncertain tax positions, and dispositions of non-deductible goodwill typically impact the Company's effective tax rate. The 2014 effective tax rate of 2,994% was primarily attributable to net changes in uncertain tax positions related to the settlement agreement associated with the Tronox Adversary Proceeding. The Company's effective tax rate decreased from 30% in 2015 to 27% in 2016 primarily due to the reversal of non-deductible goodwill due to asset divestitures in 2016.

The Company generated a net operating loss in 2016 and will file a carryback claim for a tax refund of approximately $154 million in 2017.

For additional information on income taxes, see *Note 12—Income Taxes* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

LIQUIDITY AND CAPITAL RESOURCES

millions	**2016**	2015	2014
Net cash provided by (used in) operating activities	**$ 3,000**	$ (1,877)	$ 8,466
Net cash provided by (used in) investing activities	**(2,762)**	(4,771)	(6,472)
Net cash provided by (used in) financing activities	**2,008**	220	1,675

Overview As of December 31, 2016, Anadarko had $3.2 billion of cash plus $5.0 billion of borrowing capacity under its revolving credit facilities. Substantially all of Anadarko's cash balances at December 31, 2016, were domiciled in the United States and were available to support its worldwide operations. In addition, future excess cash flows generated from the Company's international assets are available to support both its U.S. operations and corporate needs without incurring incremental U.S. income tax. Anadarko believes that its cash, anticipated operating cash flows, and proceeds from announced asset monetizations will be sufficient to fund the Company's projected 2017 operational and capital programs, providing the flexibility to accelerate activity in the Delaware and DJ basins, and potential bolt-on acquisitions in these core areas. The Company continuously monitors its liquidity position and evaluates available funding alternatives in light of current and expected conditions. The Company has a variety of funding sources available, including cash, an asset portfolio that provides ongoing cash-flow-generating capacity, opportunities for liquidity enhancement through divestitures and joint-venture arrangements that reduce future capital expenditures, and the Company's credit facilities. In addition, an effective registration statement is available to Anadarko covering the sale of WGP common units owned by the Company.

Effects of Moody's Credit Rating Downgrade As of December 31, 2016, our long-term debt was rated "BBB" with a stable outlook by S&P and Fitch. Our long-term debt was rated "Ba1" with a stable outlook by Moody's, which is below investment grade.

As a result of Moody's below-investment-grade rating of our long-term debt in February 2016, the Company's credit thresholds with certain derivative counterparties were reduced and in some cases eliminated, which required the Company to increase the amount of collateral posted with derivative counterparties when the Company's net trading position is a liability in excess of the contractual threshold. During the third quarter of 2016, Anadarko negotiated the increase of a credit threshold for an interest-rate derivative. As a result of the increased credit threshold, $200 million of collateral was returned to the Company. No counterparties have requested termination or full settlement of derivative positions. The aggregate fair value of derivative instruments with credit-risk-related contingent features for which a net liability position existed was $1.4 billion (net of $117 million of collateral) at December 31, 2016, and $1.3 billion (net of $58 million of collateral) at December 31, 2015.

Furthermore, as a result of Moody's rating, Anadarko is more likely to be required to post collateral in the form of letters of credit or cash as financial assurance of its performance under certain contractual arrangements such as pipeline transportation contracts and oil and gas sales contracts. The amount of letters of credit or cash provided as assurance of the Company's performance under these types of contractual arrangements with respect to credit-risk-related contingent features was $274 million at December 31, 2016, and zero at December 31, 2015.

Additionally, in February 2016, Moody's downgraded Anadarko's commercial paper program credit rating, which eliminated the Company's access to the commercial paper market. The Company has not issued commercial paper notes since the downgrade but instead has used the 364-Day Facility for short-term working capital requirements, as needed.

Operating Activities

One of the primary sources of variability in the Company's cash flows from operating activities is the fluctuation in commodity prices, the impact of which Anadarko partially mitigates by entering into commodity derivatives. Sales volume changes also impact cash flow but historically have not been as volatile as commodity prices. Anadarko's cash flows from operating activities are also impacted by the costs related to operations and interest payments related to the Company's outstanding debt.

Cash provided by operating activities was $3.0 billion in 2016, $4.9 billion higher compared to 2015. This increase was a result of the $5.2 billion Tronox settlement payment in 2015 and an $881 million tax refund received in 2016 related to the income tax benefit associated with the Company's 2015 tax net operating loss carryback. These increases were partially offset by $247 million related to severance costs and retirement benefits settlements in connection with the workforce reduction program and the $159.5 million payment of the CWA penalty in 2016, with the remaining decrease primarily related to lower sales due to the impact of lower commodity prices.

Cash used in operating activities was $1.9 billion in 2015, $10.4 billion lower compared to 2014. This decrease was a result of the $5.2 billion Tronox settlement payment in 2015, with the remaining decrease primarily related to lower sales due to the impact of lower commodity prices.

See *Note 16—Contingencies*—Tronox Litigation in the Notes to Consolidated Financial Statements under Item 8 of this Form 10-K.

Investing Activities

Capital Expenditures The following presents the Company's capital expenditures:

millions	**2016**	2015	2014
Cash Flows from Investing Activities			
Additions to properties and equipment [1]	**$ 3,505**	$ 6,067	$ 9,508
Adjustments for capital expenditures			
Changes in capital accruals	**(205)**	(226)	(237)
Other	**14**	47	(15)
Total capital expenditures [2]	**$ 3,314**	$ 5,888	$ 9,256

(1) Additions to properties and equipment as presented within Anadarko's cash flows from investing activities include cash payments for cost of properties, equipment, and facilities. The cost of properties includes the initial capitalization of drilling costs associated with all exploratory wells, whether or not they were deemed to have a commercially sufficient quantity of proved reserves.

(2) Includes WES capital expenditures of $491 million in 2016, $525 million in 2015, and $696 million in 2014. Capital expenditures exclude the FPSO capital lease asset; see Financing Activities—*Capital Lease Obligations* below.

During 2016, cash from operations and property divestitures were the primary sources for funding capital expenditures. The Company's capital expenditures decreased by 44% for the year ended December 31, 2016, due to the following:

- decreased development costs of $2.1 billion primarily in the U.S. onshore
- decreased exploration costs of $432 million primarily in the U.S. onshore, Colombia, and Mozambique, partially offset by increased exploration costs of $251 million in the Gulf of Mexico and Côte d'Ivoire
- decreased gathering, processing, and other capital costs of $284 million primarily in the U.S. onshore and Gulf of Mexico

The Company's capital expenditures decreased by 36% for the year ended December 31, 2015, primarily due to reduced development and exploration activity, which resulted in the following:

- decreased development costs of $2.1 billion primarily in the U.S. onshore
- lower exploration costs of $710 million primarily in the U.S. onshore and Gulf of Mexico
- lower gathering, processing, and other capital costs of $498 million primarily in the U.S. onshore

Carried-Interest Arrangements In 2014, the Company entered into a carried-interest arrangement that requires a third party to fund $442 million of Anadarko's capital costs in exchange for a 34% working interest in the Eaglebine development, located in Southeast Texas. The third-party funding is expected to cover Anadarko's future capital costs in the development through 2020. At December 31, 2016, $151 million of the $442 million carry obligation had been funded.

In 2013, the Company entered into a carried-interest arrangement that requires a third party to fund $860 million of Anadarko's capital costs in exchange for a 12.75% working interest in the Heidelberg development, located in the Gulf of Mexico. At September 30, 2016, the entire $860 million carry obligation had been funded.

Acquisitions In December 2016, the Company closed the GOM Acquisition for $1.8 billion. See *Note 3—Acquisitions, Divestitures, and Assets Held for Sale* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

In November 2014, WES acquired Nuevo Midstream, LLC (Nuevo), which owns and operates gathering and processing assets located in the Delaware basin in West Texas, for $1.6 billion, including $30 million of cash acquired. Following the acquisition, WES changed the name of Nuevo to DBM.

Divestitures Anadarko received net proceeds related to property divestiture transactions of $2.4 billion in 2016, $1.4 billion in 2015, and $5.0 billion in 2014. In December 2016, the Company entered into an agreement to sell its Marcellus oil and gas assets and certain related midstream assets for approximately $1.2 billion. These assets were classified as held for sale as of December 31, 2016. In January 2017, the Company entered into an agreement to sell its Eagleford oil and gas assets for approximately $2.3 billion. The Company expects these transactions to close in the first quarter of 2017 generating approximately $3.5 billion in cash proceeds. See *Note 3—Acquisitions, Divestitures, and Assets Held for Sale* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Financing Activities

millions except percentages	2016	2015
Anadarko	$ 12,204	$ 12,977
WES	3,091	2,691
WGP	28	—
Total debt	$ 15,323	$ 15,668
Total equity	15,497	15,457
Debt to total capitalization ratio	49.7%	50.3%

Debt Activity The following summarizes the Company's borrowing activity:

millions	2016	2015	2014	Description
Issuances	$ 800	$ —	$ —	4.850% Senior Notes due 2021 [(1)]
	1,100	—	—	5.550% Senior Notes due 2026 [(1)]
	1,100	—	—	6.600% Senior Notes due 2046 [(1)]
	500	—	—	WES 4.650% Senior Notes due 2026
	—	500	—	WES 3.950% Senior Notes due 2025
	—	101	—	TEUs - senior amortizing notes
	—	—	625	3.450% Senior Notes due 2024
	—	—	625	4.500% Senior Notes due 2044
	—	—	100	WES 2.600% Senior Notes due 2018
	200	—	400	WES 5.450% Senior Notes due 2044
Borrowings	1,750	1,800	—	364-Day Facility
	—	1,500	—	$5.0 Billion Facility
	600	400	1,160	WES RCF
	28	—	—	WGP RCF
	—	250	—	Commercial paper notes, net [(2)]
Repayments	(1,750)	—	—	5.950% Senior Notes due 2016
	(2,000)	—	—	6.375% Senior Notes due 2017
	—	—	(500)	7.625% Senior Notes due 2014
	—	—	(275)	5.750% Senior Notes due 2014
	(1,750)	(1,800)	—	364-Day Facility
	—	(1,500)	—	$5.0 Billion Facility
	(900)	(610)	(650)	WES RCF
	(250)	—	—	Commercial paper notes, net
	(34)	(16)	—	TEUs - senior amortizing notes

(1) Represent senior notes issued in March 2016.

(2) Includes repayments of $(106) million related to commercial paper notes with maturities greater than 90 days.

Senior Notes During the second quarter of 2016, the Company used proceeds from its $3.0 billion March 2016 Senior Notes issuances to purchase and retire $1.250 billion of its $2.0 billion 6.375% Senior Notes due September 2017 pursuant to a tender offer and to redeem its $1.750 billion 5.950% Senior Notes due September 2016. In December 2016, the Company redeemed its remaining $750 million 6.375% Senior Notes due September 2017. The Company recognized losses of $155 million for the early retirement and redemption of these senior notes, which included $144 million of premiums paid.

In July 2016, WES completed a public offering of $500 million aggregate principal amount of 4.650% Senior Notes due July 2026. Net proceeds were used to repay a portion of the amount outstanding under the WES RCF. In October 2016, WES completed a public offering of $200 million aggregate principal amount of 5.450% Senior Notes due April 2044. Net proceeds were primarily used to repay amounts outstanding under the WES RCF and the remaining proceeds were used for general partnership purposes, including capital expenditures.

In 2015, net proceeds from the WES 3.950% Senior Notes were used to repay WES RCF borrowings. In 2014, net proceeds from the 3.450% Senior Notes and 4.500% Senior Notes were used for general corporate purposes, and net proceeds from the WES 2.600% Senior Notes and WES 5.450% Senior Notes were used to repay WES RCF borrowings and for general partnership purposes.

Anadarko Revolving Credit Facilities Anadarko has a $3.0 billion Five-Year Facility that matures in January 2021 and a $2.0 billion 364-Day Facility. In January 2017, the Company extended the maturity date of the 364-Day Facility until January 2018.

During 2016, borrowings under the 364-Day Facility were primarily used for general short-term working capital needs. At December 31, 2016, the Company had no outstanding borrowings under the Five-Year Facility or the 364-Day Facility.

WES and WGP Revolving Credit Facilities WES has a $1.2 billion RCF, which is expandable to $1.5 billion. During 2016, WES borrowings were primarily used for general partnership purposes, including the funding of a portion of its acquisition of Springfield Pipeline LLC and capital expenditures. In December 2016, WES amended the WES RCF to extend the maturity date to February 2020. At December 31, 2016, WES was in compliance with all covenants contained in its RCF, had no outstanding borrowings under its RCF, had outstanding letters of credit of $5 million, and had available borrowing capacity of $1.195 billion.

In March 2016, WGP entered into a $250 million three-year senior secured revolving credit facility maturing in March 2019 (WGP RCF), which is expandable to $500 million, subject to receiving increased or new commitments from lenders and the satisfaction of certain other conditions. During 2016, WGP borrowings were used to fund the purchase of WES common units. At December 31, 2016, WGP had outstanding borrowings under the WGP RCF of $28 million at an interest rate of 2.77% and had available borrowing capacity of $222 million.

For additional information on the Company's revolving credit facilities, such as years of maturity, interest rates, and covenants, see *Note 11—Debt and Interest Expense* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Commercial Paper Program The Company has a commercial paper program, which allows a maximum of $3.0 billion of unsecured commercial paper notes and is supported by the Company's Five-Year Facility. As a result of Moody's downgrade of Anadarko's commercial paper program credit rating, the Company's access to the commercial paper market was eliminated. The Company repaid $250 million of commercial paper notes during the first quarter of 2016, and at December 31, 2016, there were no outstanding borrowings under the commercial paper program. See *Note 11—Debt and Interest Expense* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information.

Debt Maturities At December 31, 2016, Anadarko's scheduled debt maturities during 2017 consisted of $34 million related to the senior amortizing notes associated with the TEUs. Anadarko's Zero Coupons can be put to the Company in October of each year, in whole or in part, for the then-accreted value, which will be $883 million at the next put date in October 2017.

For additional information on the Company's debt instruments and capital lease obligations, such as transactions during the period, years of maturity, and interest rates, see *Note 11—Debt and Interest Expense* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Capital Lease Obligations Construction of the FPSO for the Company's TEN field operations in Ghana commenced in 2013. The Company recognized an asset and related obligation during the construction period. Upon completion of the construction during the third quarter of 2016, the Company reported the asset and related obligation as a capital lease of $225 million for the Company's share of the fair value of the FPSO. The Company expects to make the first payment related to the FPSO in the first quarter of 2017. At December 31, 2016, Anadarko's scheduled payments associated with capital lease obligations were $57 million during 2017. Principal payments related to capital lease obligations are reported in financing activities and interest payments related to capital lease obligations are reported in operating activities on the Company's Consolidated Statement of Cash Flows. See *Note 11—Debt and Interest Expense* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information.

Equity Transactions In September 2016, Anadarko completed a public offering of 40.5 million shares of its common stock for net proceeds of $2.16 billion. Net proceeds were primarily used to fund the GOM Acquisition. The remaining net proceeds were used for general corporate purposes.

Anadarko sold 12.5 million of its WGP common units to the public for net proceeds of $476 million in 2016, 2.3 million WGP common units to the public for net proceeds of $130 million in 2015, and approximately 6 million WGP common units to the public for net proceeds of $335 million in 2014. The proceeds for all periods were used for general corporate purposes. At December 31, 2016, Anadarko owned 179 million WGP common units, which represents an 81.6% interest in WGP.

During the second quarter of 2015, Anadarko issued 9.2 million 7.50% TEUs at a stated amount of $50.00 per TEU and raised net proceeds of $445 million. Each TEU is comprised of a prepaid equity purchase contract for WGP common units, subject to Anadarko's right to elect to issue and deliver shares of Anadarko's common stock in lieu of WGP common units, and a senior amortizing note due in June 2018. See *Note 10—Tangible Equity Units* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information.

During 2016, WES issued 14 million Series A Preferred units to private investors for net proceeds of $440 million and an additional 8 million Series A Preferred units to private investors, pursuant to the full exercise of an option granted in connection with the initial issuance, for net proceeds of $247 million.

WES can issue common units to the public under its $500 million continuous offering program, which allows for the issuance of up to an aggregate of $500 million of WES common units. The remaining amount available to be issued under this program was $442 million of WES common units at December 31, 2016. During 2015, WES issued approximately 874 thousand common units to the public and raised net proceeds of $57 million. The proceeds were used for general partnership purposes, including capital expenditures. During 2014, WES issued approximately 10 million common units to the public and raised net proceeds of $691 million. The proceeds were used to partially fund a portion of the DBM acquisition. WES used all the capacity to issue units under its $125 million continuous offering program as of the end of the third quarter of 2014.

Derivative Instruments Interest-rate swaps are used to fix or float interest rates on existing or anticipated indebtedness. The purpose of these instruments is to manage the Company's existing or anticipated exposure to interest-rate changes. The fair value of the Company's current interest-rate swap portfolio is subject to changes in interest rates. Interest-rate swap agreements were settled for total cash payments of $266 million in 2016 and $222 million in 2014. For information on derivative instruments, including cash flow treatment, see *Note 9—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K and *Effects of Moody's Credit Rating Downgrade* above.

Conveyance of Future Hard Minerals Royalty Revenues During the first quarter of 2016, the Company conveyed a limited-term nonparticipating royalty interest in certain of its coal and trona leases to a third party for $413 million, net of transaction costs. The Company made the first semi-annual payment of $25 million for royalties in 2016. For additional information on the cash flow treatment, expected timing, and scheduled payments of the conveyed royalties, see *Note 14—Conveyance of Future Hard Minerals Royalty Revenues* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Common Stock Dividends Anadarko paid dividends to its common stockholders of $105 million in 2016, $553 million in 2015, and $505 million in 2014. The Company increased the quarterly dividend paid to common stockholders from $0.18 per share during the first quarter of 2014 to $0.27 per share during the second quarter of 2014. In response to the commodity-price environment, the Company decreased the quarterly dividend to $0.05 per share in February 2016. Anadarko has paid a dividend to its common stockholders quarterly since becoming a public company in 1986.

The amount of future dividends paid to Anadarko common stockholders is determined by the Board on a quarterly basis and is based on the Company's earnings, financial conditions, capital requirements, the effect a dividend payment would have on the Company's compliance with relevant financial covenants, and other factors deemed relevant by the Board.

Distributions to Noncontrolling Interest Owners Distributions to noncontrolling interest owners primarily relate to the following:

millions	**2016**	2015	2014
WES distributions to unitholders (excluding Anadarko and WGP) [(1)]	$ **258**	$ 231	$ 175
WES distributions to Series A Preferred unit holders [(2)]	**31**	—	—
WGP distributions to unitholders (excluding Anadarko) [(3)]	**59**	37	24

(1) WES has made quarterly distributions to its unitholders since its IPO in the second quarter of 2008 and has increased its distribution from $0.30 per common unit for the third quarter of 2008 to $0.860 per common unit for the fourth quarter of 2016 (paid in February 2017).

(2) WES has made distributions of $0.68 per unit, prorated based on issuance date, to its Series A Preferred unitholders quarterly since the unit issuances in March and April 2016.

(3) WGP has made quarterly distributions to its unitholders since its IPO in December 2012 and has increased its distribution from $0.17875 per common unit for the first quarter of 2013 to $0.46250 per unit for the fourth quarter of 2016 (to be paid in February 2017).

Insurance Coverage and Other Indemnities

Anadarko maintains property and casualty insurance that includes coverage for physical damage to the Company's properties, blowout/control of a well, restoration and redrill, sudden and accidental pollution, third-party liability, workers' compensation and employers' liability, and other risks. Anadarko's insurance coverage includes deductibles that must be met prior to recovery. Additionally, the Company's insurance is subject to exclusions and limitations, and there is no assurance that such coverage will adequately protect the Company against liability or loss from all potential consequences and damages.

The Company's current insurance coverage includes (a) $400 million per occurrence from Oil Insurance Limited (OIL) for physical damage to Anadarko's properties on a replacement cost basis, blowout/control of well, restoration and redrill, and sudden and accidental pollution; (b) $1.2 billion per occurrence from the commercial markets for the items described in item (a) above, which is in excess of the OIL coverage and which follows the form of OIL coverage with certain exceptions; (c) $400 million from the commercial markets, which scales to Anadarko's working interest, for third-party liabilities, including sudden and accidental pollution and aviation liability; and (d) $275 million for aircraft liability (in addition to the third-party liability limits described in item (c) above). Anadarko does not carry significant coverage for loss of production income from any of the Company's facilities or for any losses that result from the effects of a named windstorm.

The Company's service agreements, including drilling contracts, generally indemnify Anadarko for injuries and death to employees of the service provider and subcontractors hired by the service provider as well as for property damage suffered by the service provider and its contractors. Also, these service agreements generally indemnify Anadarko for pollution originating from the equipment of any contractors or subcontractors hired by the service provider.

Off-Balance-Sheet Arrangements

Anadarko may enter into off-balance-sheet arrangements and transactions that can give rise to material off-balance-sheet obligations. The Company's material off-balance-sheet arrangements and transactions include operating lease arrangements and undrawn letters of credit. In addition, the Company enters into other contractual agreements in the normal course of business for processing, treating, transportation, and storage of oil, natural gas, and NGLs as well as for other oil and gas activities as discussed below in *Obligations*. Other than the items discussed above, there are no other transactions, arrangements, or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect Anadarko's liquidity or availability of or requirements for capital resources.

Obligations

The following is a summary of the Company's obligations at December 31, 2016:

		Obligations by Period				
millions	Note Reference [(1)]	2017	2018-2019	2020-2021	2022 and beyond	Total
Total debt						
Principal—total borrowings [(2)]	Note 11	$ 34	$ 1,409	$ 1,300	$ 13,963	$ 16,706
Interest on borrowings	Note 11	862	1,667	1,506	9,332	13,367
Capital lease obligation and interest	Note 11	57	84	85	391	617
Investee entities' debt and interest [(3)]	Note 8	61	167	196	5,060	5,484
Operating leases	Note 15	673	714	110	23	1,520
Oil and gas activities [(4)]	Note 15	478	542	178	125	1,323
Midstream and marketing activities	Note 15	850	1,666	1,433	1,099	5,048
AROs	Note 13	137	234	520	2,040	2,931
Derivative liabilities [(5)]	Note 9	159	803	438	—	1,400
Uncertain tax positions	Note 12	70	85	—	1,301	1,456
Other [(6)]		19	166	71	96	352
Total [(7)]		$ 3,400	$ 7,537	$ 5,837	$ 33,430	$ 50,204

(1) For additional information, see the *Notes to the Consolidated Financial Statements* under Item 8 of this Form 10-K.

(2) Includes the fully accreted principal amount of the Zero Coupons of approximately $2.4 billion as coming due after 2021. While the Zero Coupons do not mature until 2036, the outstanding Zero Coupons can be put to the Company each October, in whole or in part, for the then-accreted value. The Company could be required to repurchase the outstanding Zero Coupons at $883 million in October 2017 (the next potential put date).

(3) The obligations and related investments are presented net on the Company's Consolidated Balance Sheets in other long-term liabilities-other for all periods presented. Future interest payments are estimated using the relevant forward LIBOR rate curve. Further, the above table does not reflect the preferred return that Anadarko receives on its investment in these entities.

(4) The table includes long-term drilling and work-related commitments of $1.3 billion, comprised of approximately $1.1 billion related to the United States and $180 million related to international locations. These amounts are presented on an undiscounted basis and do not include purchase commitments for jointly owned fields and facilities where the Company is not the operator.

(5) Represents Anadarko's gross derivative liability after taking into account the impacts of netting margin and collateral balances deposited with counterparties.

(6) Includes environmental liabilities; for additional information, see Note 16—Contingencies in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

(7) This table does not include litigation-related contingent liabilities, the Company's pension and postretirement benefit obligations, or payments related to the conveyance of future hard minerals royalty revenues. See *Note 16—Contingencies*, *Note 18—Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans*, and *Note 14—Conveyance of Future Hard Minerals Royalty Revenues* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with GAAP requires management to make informed judgments and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses. See *Note 1—Summary of Significant Accounting Policies* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for discussion of the Company's significant accounting policies. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates. Management considers the following to be its most critical accounting estimates that involve judgment. The selection, development, and disclosure of these estimates is discussed with the Company's Audit Committee.

Proved Reserves

Methodology Anadarko estimates its proved oil and gas reserves according to the definition of proved reserves provided by the SEC and the Financial Accounting Standards Board. This definition includes oil, natural gas, and NGLs that geological and engineering data demonstrate with reasonable certainty to be economically producible in future periods from known reservoirs under existing economic conditions, operating methods, government regulations, etc. (at prices and costs as of the date the estimates are made). Prices include consideration of price changes provided only by contractual arrangements, and do not include adjustments based on expected future conditions. For reserves information, see *Oil and Gas Properties and Activities—Proved Reserves* under Items 1 and 2 of this Form 10-K and the *Supplemental Information on Oil and Gas Exploration and Production Activities* under Item 8 of this Form 10-K.

Judgments and uncertainties Engineering estimates of the quantities of proved reserves are inherently imprecise and represent only approximate amounts because of the judgments involved in developing such information. The Company's estimates of proved reserves are made using available geological and reservoir data as well as production performance data. The reliability of these estimates at any point in time depends on both the quality and quantity of the technical and economic data and the efficiency of extracting and processing the hydrocarbons. These estimates are reviewed annually by internal reservoir engineers and revised, either upward or downward, as warranted by additional data. Revisions are necessary due to changes in, among other things, development plans, reservoir performance, prices, economic conditions, and governmental restrictions as well as changes in the expected recovery associated with infill drilling. Decreases in prices, for example, may cause a reduction in some proved reserves due to reaching economic limits at an earlier projected date.

A material adverse change in the estimated volumes of proved reserves could have a negative impact on DD&A and could result in property impairments. If the estimates of proved reserves used in the UOP calculations had been lower by five percent across all properties, DD&A in 2016 would have increased by approximately $211 million.

Exploratory Costs

Methodology Under the successful efforts method of accounting, exploratory drilling costs are initially capitalized pending the determination of proved reserves. If proved reserves are found, drilling costs remain capitalized and are classified as proved properties. For exploratory wells that find reserves that cannot be classified as proved when drilling is completed, costs continue to be capitalized as suspended exploratory drilling costs if there have been sufficient reserves found to justify completion as a producing well and sufficient progress is being made in assessing the reserves and the economic and operating viability of the project. At the end of each quarter, management reviews the status of all suspended exploratory drilling costs in light of ongoing exploration activities, in particular, whether the Company is making sufficient progress in its ongoing exploration and appraisal efforts or, in the case of discoveries requiring government sanctioning, analyzing whether development negotiations are underway and proceeding as planned.

Judgments and uncertainties Significant management judgment is required to determine whether sufficient progress has been made in assessing the reserves and the economic and operating viability of the project to continue capitalization of the exploratory drilling costs. In making this determination all relevant facts and circumstances shall be evaluated, and no single indicator is determinative. Relevant facts and circumstances include, but are not limited to, commitment of project personnel, costs being incurred to assess the reserves and their potential development, assessment in progress covering the economic, legal, political, and environmental aspects of the potential development, and the existence or active negotiations of agreements with governments or sales contracts with customers. The determination of proved reserves may take longer than one year in certain areas (generally in deepwater and international locations) depending on, among other things, the amount of hydrocarbons discovered, the outcome of planned geological and engineering studies, the need for additional appraisal drilling activities to determine whether the discovery is sufficient to support an economic development plan, and government sanctioning of development activities in certain international locations.

If management determines that future appraisal drilling or development activities are unlikely to occur, associated suspended exploratory well costs are expensed. Therefore, at any point in time, the Company may have capitalized costs on its Consolidated Balance Sheets associated with exploratory wells that may be charged to exploration expense in future periods. See *Note 6—Suspended Exploratory Well Costs* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for additional information.

Fair Value

Methodology The Company estimates fair value of long-lived assets for impairment testing, reporting units for goodwill impairment testing when necessary, assets and liabilities acquired in a business combination or exchanged in non-monetary transactions, pension plan assets, and initial measurements of AROs.

Judgments and uncertainties When the Company is required to measure fair value and there is not a market-observable price for the asset or liability or for a similar asset or liability, the Company uses the cost or income approaches depending on the quality of information available to support management's assumptions. The cost approach is based on management's best estimate of the current asset replacement cost. The income approach is based on management's best assumptions regarding expectations of future net cash flows and discounts the expected cash flows using a commensurate risk-adjusted discount rate. Such evaluations involve significant judgment, and the results are based on expected future events or conditions such as sales prices, estimates of future oil and gas production or throughput, development and operating costs and the timing thereof, economic and regulatory climates, and other factors, most of which are often outside of management's control. However, assumptions used reflect a market participant's view of long-term prices, costs, and other factors and are consistent with assumptions used in the Company's business plans and investment decisions.

Impairments of Proved Oil and Natural-Gas Properties

Methodology Proved oil and natural-gas properties are assessed for impairment when facts and circumstances indicate that net book values may not be recoverable. When impairment indicators are present, an undiscounted cash flow test is performed at the lowest level for which identifiable cash flows are independent of cash flows from other assets. If the sum of the undiscounted future net cash flows is less than the net book value of the property, the property's fair value is estimated and an impairment loss is recognized for the excess, if any, of the property's net book value over its estimated fair value.

Judgments and uncertainties The primary assumptions used to estimate undiscounted future net cash flows include anticipated future production, commodity prices, and capital and operating costs. In most cases, the assumption that generates the most variability in undiscounted future net cash flows is future oil and natural-gas prices. For impairment testing, the Company used the five-year forward strip prices for oil and natural gas, with prices subsequent to the fifth year held constant as the benchmark price in the undiscounted future net cash flows. Due to the volatility of crude oil, natural gas, and NGL prices, these cash flow estimates are inherently imprecise. Capital and operating costs were estimated assuming 0% escalation for years where the average oil strip price was below $50 per Bbl and 1% escalation for years where the average oil strip price exceeded $50 per Bbl.

Unfavorable changes in any of the primary assumptions could result in a reduction in undiscounted future cash flows and could indicate property impairment. Uncertainties related to the primary assumptions could affect the timing of an impairment.

Impairments of Unproved Oil and Natural-Gas Properties

Methodology Acquisition costs of unproved oil and natural-gas properties are periodically assessed for impairment and are transferred to proved oil and gas properties to the extent the costs are associated with successful exploration activities. The Company has classified unproved oil and natural-gas properties into three categories: significant, significant where probable and possible reserve estimations are available, and individually insignificant. Significant undeveloped leases are assessed individually for impairment and a valuation allowance is provided if impairment is indicated. In situations where fair values have been allocated to a significant unproved property based on estimations of probable and/or possible reserves as the result of a business combination or other purchase of proved and unproved properties, a future cash flow analysis is used to assess the property for impairment in addition to consideration of reserve volumes needed to transfer the balance of unproved property to proved leasehold. Unproved oil and gas properties with individually insignificant lease acquisition costs are amortized on a group basis (thereby establishing a valuation allowance) over the average lease terms at rates that provide for full amortization of unsuccessful leases upon lease expiration or abandonment.

Judgments and uncertainties In determining whether a significant unproved property is impaired numerous factors are considered including, but not limited to, current exploration plans, favorable or unfavorable exploration activity on the property being evaluated and/or adjacent properties, our geologists' evaluation of the property, and the remaining months in the lease term for the property. In situations where probable and possible reserves are available, cash flows used in the impairment analysis are determined based upon management's estimates of probable and possible reserves, future commodity prices, and future costs to produce the reserves. If undiscounted future net cash flows are less than the carrying value of the property, indicating impairment, the cash flows are discounted and compared to the carrying value for determining the amount of the impairment loss to record. The Company utilizes the same pricing assumptions discussed above in Impairments of Proved Oil and Natural-Gas Properties. Uncertainties related to the primary assumptions or unfavorable revisions in estimated reserve quantities could cause a reduction in the value of a property and therefore indicate an impairment. Management's assessment of the results of exploration activities, availability of funds for future activities, and the current and projected political and regulatory climate in areas in which we operate also impact the amounts and timing of impairment provisions.

Purchase Price Allocations

Methodology In connection with a business combination accounted for under the acquisition method, the acquiring company must recognize and measure assets acquired and liabilities assumed at fair value as of the acquisition date. Deferred taxes must be recorded for any differences between the assigned values and tax bases of assets and liabilities. Any excess of the purchase price over fair value assigned to assets and liabilities is recorded as goodwill. Any excess of fair value assigned to assets and liabilities over the purchase price is recorded as a gain from a bargain purchase. The amount of goodwill or gain from a bargain purchase recorded in any particular business combination can vary significantly depending upon the values attributed to assets acquired and liabilities assumed.

Judgments and uncertainties In estimating the fair values of assets acquired and liabilities assumed in a business combination, various assumptions are made. The most significant assumptions relate to the estimated fair values assigned to proved and unproved crude oil and natural gas properties. If sufficient market data is not available regarding the fair values of proved and unproved properties, estimates of the fair value of crude oil, natural-gas and NGL reserves are prepared. Estimates of future prices to apply to the estimated reserves quantities acquired and estimates of future operating and development costs are used to estimate future net cash flows. For estimated proved reserves, the future net cash flows are discounted using a market-based discount rate determined appropriate at the time of the acquisition. Estimated deferred taxes are based on available information concerning the tax bases of assets acquired and liabilities assumed and loss carryforwards at the acquisition date, although such estimates may change in the future as additional information becomes known.

Estimated fair values of assets acquired can have a significant effect on results of operations in the future. A higher fair value assigned to a property results in higher DD&A expense, which results in lower net earnings. Fair values are based on estimates of future commodity prices, reserves quantities, operating expenses, and development costs. This increases the likelihood of impairment if future commodity prices or reserves quantities are lower than those originally used to determine fair value, or if future operating expenses or development costs are higher than those originally used to determine fair value. Impairment would have no effect on cash flows but would result in a decrease in net income for the period in which the impairment is recorded.

Goodwill Impairments

Methodology The Company tests goodwill for impairment annually in October (or more frequently as circumstances dictate). The Company first assesses whether an impairment of goodwill is indicated through a qualitative assessment to determine the likelihood of whether the fair value of the reporting unit is less than its carrying amount, including goodwill. If the Company concludes it is more likely than not that fair value of the reporting unit exceeds the related carrying amount, then goodwill is not impaired and further testing is not necessary. If the qualitative assessment indicates fair value of the reporting unit may be less than its carrying amount, the Company compares the estimated fair value of the reporting unit to which goodwill is assigned to the carrying amount of the associated net assets, including goodwill, and determines whether impairment is necessary.

When evaluating whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount, the Company assesses relevant events and circumstances, including the following:

- significant changes in the stock price of Anadarko, WES, and WGP
- significant declines in commodity prices
- significant increases in cost factors such as costs of drilling, production costs, and gathering, processing, and other transportation costs
- impairments recognized by the Company
- acquisitions and disposals of assets
- changes to the Company's reserves, including changes due to fluctuations in commodity prices and updates to the Company's plans or forecasts
- significant declines in trading multiples for midstream peers

Judgments and uncertainties Because quoted market prices for the Company's reporting units are not available, management applies judgment in determining the estimated fair value of reporting units for purposes of performing goodwill impairment tests, when such tests are necessary. Management uses information available to make these fair-value estimates, including the present values of expected future cash flows using discount rates commensurate with the risks associated with the assets and the oil and gas exploration and production reporting unit, control premiums and market multiples of earnings before interest, taxes, depreciation, and amortization (EBITDA) for the gathering and processing and transportation reporting units.

In estimating the fair value of its oil and gas exploration and production reporting unit, the Company assumes production profiles used in its estimation of reserves that are disclosed in the Company's supplemental oil and gas disclosures, market prices based on the forward price curve for oil and gas at the test date (adjusted for location and quality differentials), capital and operating costs consistent with pricing and expected inflation rates, and discount rates that management believes a market participant would use based upon the risks inherent in Anadarko's operations. Management also includes control premium assumptions based on observable market information regarding how a market participant would value the oil and gas exploration and production reporting unit as a whole rather than as individual properties that are part of an oil and gas portfolio.

The Company estimates fair value for the WES gathering and processing, WES transportation, and other gathering and processing reporting units by applying an estimated multiple to projected EBITDA. The Company considered observable transactions in the market and trading multiples for peers in determining an appropriate multiple to apply against the Company's projected EBITDA for these reporting units.

A lower fair-value estimate in the future for any of these reporting units could result in impairment of goodwill. Factors that could trigger a lower fair-value estimate include significant declines in commodity prices, decreases in proved reserves, changes in exploration or development plans, significant property impairments, increases in operating or drilling costs, significant changes in regulations, or other negative changes to the economic environment in which Anadarko operates.

Contingencies

Methodology The Company is subject to various legal proceedings, claims, and liabilities that arise in the ordinary course of business. Except for contingencies acquired in a business combination, which are recorded at fair value at the time of acquisition, the Company accrues losses when such losses are probable and reasonably estimable. If the Company determines that a loss is probable and cannot estimate a specific amount for that loss, but can estimate a range of loss, the best estimate within the range is accrued. If no amount within the range is a better estimate than any other, the minimum amount of the range is accrued. The Company's in-house legal counsel personnel regularly assess contingent liabilities and, in certain circumstances, consult with third-party legal counsel or consultants to assist in the evaluation of the Company's liability for these contingencies.

Judgments and uncertainties Management makes judgments and estimates when it establishes liabilities for litigation and other contingent matters. Estimates of litigation-related liabilities are based on the facts and circumstances of the individual case and on information currently available to the Company. The extent of information available varies based on the status of the litigation and the Company's evaluation of the claim and legal arguments. In future periods, a number of factors could significantly change the Company's estimate of litigation-related liabilities, including discovery activities; briefings filed with the relevant court; rulings from the court made pre-trial, during trial, or at the conclusion of any trial; and similar cases involving other plaintiffs and defendants that may set or change legal precedent. As events unfold throughout the litigation process, the Company evaluates the available information and may consult with third-party legal counsel to determine whether liability accruals should be established or adjusted.

Income Taxes

Methodology We are subject to income taxes in numerous taxing jurisdictions worldwide. The amount of income taxes recorded by the Company requires interpretations of complex rules and regulations of various tax jurisdictions throughout the world. The Company has recognized deferred tax assets and liabilities for temporary differences, operating losses, and tax-credit carryforwards.

The deferred tax assets may be reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax assets will not be realized. The Company routinely assesses the realizability of its deferred tax assets by analyzing the reversal periods of available net operating loss carryforwards and credit carryforwards, temporary differences in tax assets and liabilities, the availability of tax planning strategies, and estimates of future taxable income and other factors.

The Company also routinely assesses potential uncertain tax positions and, if required, establishes accruals for such amounts, including interest where appropriate. The Company recognizes a tax benefit from an uncertain tax position when it is more likely than not that the position will be sustained upon examination, based on the technical merits of the position.

Judgments and uncertainties The accruals for deferred tax assets and liabilities, including deferred state income tax assets and liabilities, are subject to significant judgment by management and are reviewed and adjusted routinely based on changes in facts and circumstances. The assessment of potential uncertain tax positions requires a significant amount of judgment and are reviewed and adjusted on a periodic basis, taking into consideration the progress of ongoing tax audits, case law, and new legislation. Although management considers its tax accruals adequate, material changes in these accruals may occur in the future based on the progress of ongoing tax audits, changes in legislation, and resolution of pending tax matters. Additionally, numerous judgments and assumptions are inherent in our estimates of future taxable income used to assess the realizability of certain deferred tax assets. The estimates used are based on assumptions of proved oil and gas reserves, selling prices, and development assumptions that are consistent with the Company's internal business plans.

RECENT ACCOUNTING DEVELOPMENTS

See *Note 1—Summary of Significant Accounting Policies* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K for discussion of recent accounting developments affecting the Company.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The Company's primary market risks are attributable to fluctuations in energy prices and interest rates. These risks can affect revenues and cash flows, and the Company's risk-management policies provide for the use of derivative instruments to manage these risks. The types of commodity derivative instruments used by the Company include futures, swaps, options, and fixed-price physical-delivery contracts. The volume of commodity derivatives entered into by the Company is governed by risk-management policies and may vary from year to year. Both exchange and over-the-counter traded derivative instruments may be subject to margin-deposit requirements, and the Company may be required from time to time to deposit cash or provide letters of credit with exchange brokers or counterparties to satisfy these margin requirements. For additional information relating to the Company's derivative and financial instruments, see *Note 9—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

COMMODITY-PRICE RISK The Company's most significant market risk relates to prices for oil, natural gas, and NGLs. Management expects energy prices to remain unpredictable and potentially volatile. As energy prices decline or rise significantly, revenues and cash flows are likewise affected. In addition, a non-cash write-down of the Company's oil and gas properties or goodwill may be required if commodity prices experience a significant decline. Below is a sensitivity analysis for the Company's commodity-price-related derivative instruments.

Derivative Instruments Held for Non-Trading Purposes The Company had derivative instruments in place to reduce the price risk associated with future production of 33 MMBbls of oil, 354 Bcf of natural gas, and 1 MMBbls of NGLs at December 31, 2016, with a net derivative liability position of $136 million. Based on actual derivative contractual volumes, a 10% increase in underlying commodity prices would reduce the fair value of these derivatives by $199 million, while a 10% decrease in underlying commodity prices would increase the fair value of these derivatives by $168 million. However, any cash received or paid to settle these derivatives would be substantially offset by the sales value of production covered by the derivative instruments.

Derivative Instruments Held for Trading Purposes At December 31, 2016, the Company had a net derivative asset position of $6 million on outstanding derivative instruments entered into for trading purposes. Based on actual derivative contractual volumes, a 10% increase or decrease in underlying commodity prices would not materially impact the Company's gains or losses on these derivative instruments.

For additional information regarding the Company's marketing and trading portfolio, see *Marketing Activities* under Items 1 and 2 of this Form 10-K.

INTEREST-RATE RISK Borrowings, if any, under each of the 364-Day Facility, the Five-Year Facility, the WES RCF, and the WGP RCF are subject to variable interest rates. The balance of Anadarko's long-term debt on the Company's Consolidated Balance Sheets has fixed interest rates. The Company has $2.9 billion of LIBOR-based obligations that are presented on the Company's Consolidated Balance Sheets net of preferred investments in two noncontrolled entities. These obligations give rise to minimal net interest-rate risk because coupons on the related preferred investments are also LIBOR-based. While a 10% change in LIBOR would not materially impact the Company's interest cost, it would affect the fair value of outstanding fixed-rate debt.

At December 31, 2016, the Company had a net derivative liability position of $1.3 billion related to interest-rate swaps. A 10% increase (decrease) in the three-month LIBOR interest-rate curve would decrease (increase) the aggregate fair value of outstanding interest-rate swap agreements by $90 million. However, any change in the interest-rate derivative gain or loss could be substantially offset by changes in actual borrowing costs associated with future debt issuances. For a summary of the Company's outstanding interest-rate derivative positions, see *Note 9—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 8 of this Form 10-K.

Item 8. Financial Statements and Supplementary Data

ANADARKO PETROLEUM CORPORATION

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

ANADARKO PETROLEUM CORPORATION

REPORT OF MANAGEMENT

Management prepared, and is responsible for, the Consolidated Financial Statements and the other information appearing in this annual report. The Consolidated Financial Statements present fairly the Company's financial condition, results of operations and cash flows in conformity with accounting principles generally accepted in the United States. In preparing its Consolidated Financial Statements, the Company includes amounts that are based on estimates and judgments that Management believes are reasonable under the circumstances. The Company's financial statements have been audited by KPMG LLP, an independent registered public accounting firm appointed by the Audit Committee of the Board of Directors. Management has made available to KPMG LLP all of the Company's financial records and related data, as well as the minutes of the stockholders' and Directors' meetings.

MANAGEMENT'S ASSESSMENT OF INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Anadarko's internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2016. This assessment was based on criteria established in the *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations (COSO) of the Treadway Commission. Based on our assessment, we believe that the Company's internal control over financial reporting was effective as of December 31, 2016.

KPMG LLP has issued an attestation report on the Company's internal control over financial reporting as of December 31, 2016.

/s/ R. A. WALKER

R. A. Walker
Chairman, President and Chief Executive Officer

/s/ ROBERT G. GWIN

Robert G. Gwin
Executive Vice President, Finance and Chief Financial Officer

February 17, 2017

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Anadarko Petroleum Corporation:

We have audited Anadarko Petroleum Corporation's internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Anadarko Petroleum Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Assessment of Internal Control over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Anadarko Petroleum Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Anadarko Petroleum Corporation and subsidiaries as of December 31, 2016 and 2015, and the related consolidated statements of operations, comprehensive income, equity, and cash flows for each of the years in the three-year period ended December 31, 2016, and our report dated February 17, 2017 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Houston, Texas
February 17, 2017

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders
Anadarko Petroleum Corporation:

We have audited the accompanying consolidated balance sheets of Anadarko Petroleum Corporation and subsidiaries as of December 31, 2016 and 2015, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the years in the three-year period ended December 31, 2016. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Anadarko Petroleum Corporation and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the years in the three–year period ended December 31, 2016, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Anadarko Petroleum Corporation's internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 17, 2017 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Houston, Texas
February 17, 2017

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF INCOME

millions except per-share amounts	Years Ended December 31, 2016	2015	2014
Revenues and Other			
Oil sales	**$ 4,668**	$ 5,420	$ 9,748
Natural-gas sales	**1,564**	2,007	3,849
Natural-gas liquids sales	**921**	833	1,572
Gathering, processing, and marketing sales	**1,294**	1,226	1,206
Gains (losses) on divestitures and other, net	**(578)**	(788)	2,095
Total	**7,869**	8,698	18,470
Costs and Expenses			
Oil and gas operating	**811**	1,014	1,171
Oil and gas transportation	**1,002**	1,117	1,116
Exploration	**946**	2,644	1,639
Gathering, processing, and marketing	**1,087**	1,054	1,030
General and administrative	**1,440**	1,176	1,316
Depreciation, depletion, and amortization	**4,301**	4,603	4,550
Production, property, and other taxes	**536**	553	1,244
Impairments	**227**	5,075	836
Other operating expense	**118**	271	165
Total	**10,468**	17,507	13,067
Operating Income (Loss)	**(2,599)**	(8,809)	5,403
Other (Income) Expense			
Interest expense	**890**	825	772
Loss on early extinguishment of debt	**155**	—	—
(Gains) losses on derivatives, net	**286**	(99)	197
Other (income) expense, net	**(101)**	149	20
Tronox-related contingent loss	**—**	5	4,360
Total	**1,230**	880	5,349
Income (Loss) Before Income Taxes	**(3,829)**	(9,689)	54
Income tax expense (benefit)	**(1,021)**	(2,877)	1,617
Net Income (Loss)	**(2,808)**	(6,812)	(1,563)
Net income (loss) attributable to noncontrolling interests	**263**	(120)	187
Net Income (Loss) Attributable to Common Stockholders	**$ (3,071)**	$ (6,692)	$ (1,750)
Per Common Share			
Net income (loss) attributable to common stockholders—basic	**$ (5.90)**	$ (13.18)	$ (3.47)
Net income (loss) attributable to common stockholders—diluted	**$ (5.90)**	$ (13.18)	$ (3.47)
Average Number of Common Shares Outstanding—Basic	**522**	508	506
Average Number of Common Shares Outstanding—Diluted	**522**	508	506
Dividends (per Common Share)	**$ 0.20**	$ 1.08	$ 0.99

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
millions	**2016**	2015	2014
Net Income (Loss)	**$ (2,808)**	$ (6,812)	$ (1,563)
Other Comprehensive Income (Loss)			
Adjustments for derivative instruments			
Reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	**8**	10	9
Income taxes on reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	**(3)**	(4)	(3)
Total adjustments for derivative instruments, net of taxes	**5**	6	6
Adjustments for pension and other postretirement plans			
Net gain (loss) incurred during period	**(175)**	49	(405)
Income taxes on net gain (loss) incurred during period	**68**	(18)	149
Prior service credit (cost) incurred during period	**—**	89	—
Income taxes on prior service credit (cost) incurred during period	**—**	(33)	—
Amortization of net actuarial (gain) loss to general and administrative expense	**188**	63	27
Income taxes on amortization of net actuarial (gain) loss to general and administrative expense	**(73)**	(20)	(9)
Amortization of net prior service (credit) cost to general and administrative expense	**(34)**	(4)	—
Income taxes on amortization of net prior service (credit) cost to general and administrative expense	**13**	2	—
Total adjustments for pension and other postretirement plans, net of taxes	**(13)**	128	(238)
Total	**(8)**	134	(232)
Comprehensive Income (Loss)	**(2,816)**	(6,678)	(1,795)
Comprehensive income (loss) attributable to noncontrolling interests	**263**	(120)	187
Comprehensive Income (Loss) Attributable to Common Stockholders	**$ (3,079)**	$ (6,558)	$ (1,982)

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED BALANCE SHEETS

millions	December 31, 2016	December 31, 2015
ASSETS		
Current Assets		
Cash and cash equivalents ($359 and $100 related to VIEs)	**$ 3,184**	$ 939
Accounts receivable (net of allowance of $14 and $11)		
Customers ($70 and $81 related to VIEs)	**1,007**	652
Others ($80 and $84 related to VIEs)	**721**	1,817
Other current assets	**354**	573
Total	**5,266**	3,981
Properties and Equipment		
Cost	**69,013**	70,683
Less accumulated depreciation, depletion, and amortization	**36,845**	36,932
Net properties and equipment ($5,050 and $4,859 related to VIEs)	**32,168**	33,751
Other Assets ($609 and $644 related to VIEs)	**2,226**	2,268
Goodwill and Other Intangible Assets ($1,221 and $1,220 related to VIEs)	**5,904**	6,331
Total Assets	**$ 45,564**	$ 46,331
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable ($239 and $179 related to VIEs)	**$ 2,288**	$ 2,850
Accrued expenses	**386**	424
Interest payable	**244**	247
Production, property, and other taxes payable ($24 and $18 related to VIEs)	**239**	318
Current asset retirement obligations	**129**	309
Short-term debt	**42**	32
Total	**3,328**	4,180
Long-term Debt	**15,281**	15,636
Other Long-term Liabilities		
Deferred income taxes	**4,324**	5,400
Asset retirement obligations ($140 and $127 related to VIEs)	**2,802**	1,750
Other	**4,332**	3,908
Total	**11,458**	11,058
Equity		
Stockholders' equity		
Common stock, par value $0.10 per share (1.0 billion shares authorized, 572.0 million and 528.3 million shares issued)	**57**	52
Paid-in capital	**11,875**	9,265
Retained earnings	**1,704**	4,880
Treasury stock (20.8 million and 20.0 million shares)	**(1,033)**	(995)
Accumulated other comprehensive income (loss)	**(391)**	(383)
Total Stockholders' Equity	**12,212**	12,819
Noncontrolling interests	**3,285**	2,638
Total Equity	**15,497**	15,457
Total Liabilities and Equity	**$ 45,564**	$ 46,331

Parenthetical references reflect amounts as of December 31, 2016, and December 31, 2015.

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF EQUITY

	Total Stockholders' Equity						
millions	Common Stock	Paid-in Capital	Retained Earnings	Treasury Stock	Accumulated Other Comprehensive Income (Loss)	Non-controlling Interests	Total Equity
Balance at December 31, 2013	$ 52	$ 8,629	$ 14,356	$ (895)	$ (285)	$ 1,793	$ 23,650
Net income (loss)	—	—	(1,750)	—	—	187	(1,563)
Common stock issued	—	286	—	—	—	—	286
Dividends—common stock	—	—	(505)	—	—	—	(505)
Repurchase of common stock	—	—	—	(45)	—	—	(45)
Subsidiary equity transactions	—	90	24	—	—	829	943
Distributions to noncontrolling interest owners	—	—	—	—	—	(216)	(216)
Reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	—	—	—	—	6	—	6
Adjustments for pension and other postretirement plans	—	—	—	—	(238)	—	(238)
Balance at December 31, 2014	52	9,005	12,125	(940)	(517)	2,593	22,318
Net income (loss)	—	—	(6,692)	—	—	(120)	(6,812)
Common stock issued	—	209	—	—	—	—	209
Dividends—common stock	—	—	(553)	—	—	—	(553)
Repurchase of common stock	—	—	—	(55)	—	—	(55)
Subsidiary equity transactions	—	51	—	—	—	99	150
Issuance of tangible equity units	—	—	—	—	—	348	348
Distributions to noncontrolling interest owners	—	—	—	—	—	(282)	(282)
Reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	—	—	—	—	6	—	6
Adjustments for pension and other postretirement plans	—	—	—	—	128	—	128
Balance at December 31, 2015	**52**	**9,265**	**4,880**	**(995)**	**(383)**	**2,638**	**15,457**
Net income (loss)	—	—	**(3,071)**	—	—	**263**	**(2,808)**
Common stock issued	**5**	**2,347**	—	—	—	—	**2,352**
Dividends—common stock	—	—	**(105)**	—	—	—	**(105)**
Repurchase of common stock	—	—	—	**(38)**	—	—	**(38)**
Subsidiary equity transactions	—	**263**	—	—	—	**746**	**1,009**
Distributions to noncontrolling interest owners	—	—	—	—	—	**(362)**	**(362)**
Reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	—	—	—	—	**5**	—	**5**
Adjustments for pension and other postretirement plans	—	—	—	—	**(13)**	—	**(13)**
Balance at December 31, 2016	**$ 57**	**$11,875**	**$ 1,704**	**$ (1,033)**	**$ (391)**	**$ 3,285**	**$ 15,497**

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
millions	**2016**	2015	2014
Cash Flows from Operating Activities			
Net income (loss)	**$ (2,808)**	$ (6,812)	$ (1,563)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities			
Depreciation, depletion, and amortization	**4,301**	4,603	4,550
Deferred income taxes	**(1,238)**	(3,152)	(105)
Dry hole expense and impairments of unproved properties	**613**	2,267	1,245
Impairments	**227**	5,075	836
(Gains) losses on divestitures, net	**757**	1,022	(1,891)
Loss on early extinguishment of debt	**155**	—	—
Total (gains) losses on derivatives, net	**292**	(100)	207
Operating portion of net cash received (paid) in settlement of derivative instruments	**267**	335	371
Other	**342**	320	327
Changes in assets and liabilities			
Tronox-related contingent liability	**—**	(5,210)	4,360
(Increase) decrease in accounts receivable	**677**	(2)	103
Increase (decrease) in accounts payable and accrued expenses	**(669)**	(995)	97
Other items, net	**84**	772	(71)
Net cash provided by (used in) operating activities	**3,000**	(1,877)	8,466
Cash Flows from Investing Activities			
Additions to properties and equipment	**(3,505)**	(6,067)	(9,508)
Acquisition of businesses	**(1,740)**	(3)	(1,527)
Divestitures of properties and equipment and other assets	**2,356**	1,415	4,968
Other, net	**127**	(116)	(405)
Net cash provided by (used in) investing activities	**(2,762)**	(4,771)	(6,472)
Cash Flows from Financing Activities			
Borrowings, net of issuance costs	**6,042**	4,632	2,879
Repayments of debt	**(6,832)**	(4,033)	(1,425)
Financing portion of net cash received (paid) for derivative instruments	**(333)**	(35)	(222)
Increase (decrease) in outstanding checks	**(103)**	(23)	62
Dividends paid	**(105)**	(553)	(505)
Repurchase of common stock	**(38)**	(55)	(45)
Issuance of common stock, including tax benefit on share-based compensation awards	**2,188**	34	121
Sale of subsidiary units	**1,163**	187	1,026
Issuance of tangible equity units — equity component	**—**	348	—
Distributions to noncontrolling interest owners	**(362)**	(282)	(216)
Proceeds from conveyance of future hard minerals royalty revenues, net of transaction costs	**413**	—	—
Payments of future hard minerals royalty revenues conveyed	**(25)**	—	—
Net cash provided by (used in) financing activities	**2,008**	220	1,675
Effect of Exchange Rate Changes on Cash	**(1)**	(2)	2
Net Increase (Decrease) in Cash and Cash Equivalents	**2,245**	(6,430)	3,671
Cash and Cash Equivalents at Beginning of Period	**939**	7,369	3,698
Cash and Cash Equivalents at End of Period	**$ 3,184**	$ 939	$ 7,369

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2016, 2015, AND 2014

1. Summary of Significant Accounting Policies

General Anadarko Petroleum Corporation is engaged in the exploration, development, production, and marketing of oil, natural gas, and NGLs, and in the marketing of anticipated production of LNG. In addition, the Company engages in the gathering, processing, treating, and transporting of oil, natural gas, and NGLs. The Company also participates in the hard-minerals business through royalty arrangements.

Basis of Presentation The consolidated financial statements have been prepared in conformity with GAAP. Certain prior-period amounts have been reclassified to conform to the current-year presentation.

The consolidated financial statements include the accounts of Anadarko and subsidiaries in which Anadarko holds, directly or indirectly, more than 50% of the voting rights and VIEs for which Anadarko is the primary beneficiary. All intercompany transactions have been eliminated. Undivided interests in oil and natural-gas exploration and production joint ventures are consolidated on a proportionate basis. Investments in noncontrolled entities, over which Anadarko has the ability to exercise significant influence over operating and financial policies, and VIEs for which Anadarko is not the primary beneficiary are accounted for using the equity method. In applying the equity method of accounting, the investments are initially recognized at cost, and subsequently adjusted for the Company's proportionate share of earnings, losses, and distributions. Other investments are carried at original cost. Investments accounted for using the equity method and cost method are included in other assets.

Use of Estimates The preparation of financial statements in accordance with GAAP requires management to make informed judgments and estimates that affect the reported amounts of assets, liabilities, revenues, and expenses. Management evaluates its estimates and related assumptions regularly, including those related to proved reserves; the value of properties and equipment; goodwill; intangible assets; AROs; litigation liabilities; environmental liabilities; pension assets, liabilities, and costs; income taxes; and fair values. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates.

Fair Value Fair value is defined as the price that would be received to sell an asset or the price paid to transfer a liability in an orderly transaction between market participants at the measurement date. Inputs used in determining fair value are characterized according to a hierarchy that prioritizes those inputs based on the degree to which they are observable. The three input levels of the fair-value hierarchy are as follows:

Level 1—Inputs represent unadjusted quoted prices in active markets for identical assets or liabilities (for example, exchange-traded futures contracts for which parties are willing to transact at the exchange-quoted price).

Level 2—Inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly (for example, quoted market prices for similar assets or liabilities in active markets or quoted market prices for identical assets or liabilities in markets not considered to be active, inputs other than quoted prices that are observable for the asset or liability, or market-corroborated inputs).

Level 3—Inputs that are not observable from objective sources such as the Company's internally developed assumptions used in pricing an asset or liability (for example, an estimate of future cash flows used in the Company's internally developed present value of future cash flows model that underlies the fair-value measurement).

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2016, 2015, AND 2014

1. Summary of Significant Accounting Policies (Continued)

In determining fair value, the Company uses observable market data when available, or models that incorporate observable market data. When the Company is required to measure fair value and there is not a market-observable price for the asset or liability or for a similar asset or liability, the Company uses the cost or income approaches depending on the quality of information available to support management's assumptions. The cost approach is based on management's best estimate of the current asset replacement cost. The income approach is based on management's best assumptions regarding expectations of future net cash flows and discounts the expected cash flows using a commensurate risk-adjusted discount rate. Such evaluations involve significant judgment, and the results are based on expected future events or conditions such as sales prices, estimates of future oil and gas production or throughput, development and operating costs and the timing thereof, economic and regulatory climates, and other factors, most of which are often outside of management's control. However, assumptions used reflect a market participant's view of long-term prices, costs, and other factors and are consistent with assumptions used in the Company's business plans and investment decisions.

In arriving at fair-value estimates, the Company uses relevant observable inputs available for the valuation technique employed. If a fair-value measurement reflects inputs at multiple levels within the hierarchy, the fair-value measurement is characterized based on the lowest level of input that is significant to the fair-value measurement. For Anadarko, recurring fair-value measurements are performed for interest-rate derivatives, commodity derivatives, and investments in trading securities.

The carrying amount of cash and cash equivalents, accounts receivable, and accounts payable reported on the Company's Consolidated Balance Sheets approximates fair value. The fair value of debt is the estimated amount the Company would have to pay to repurchase its debt, including any premium or discount attributable to the difference between the stated interest rate and market interest rate at each balance sheet date. Debt fair values, as disclosed in *Note 11—Debt and Interest Expense*, are based on quoted market prices for identical instruments, if available, or based on valuations of similar debt instruments.

Non-financial assets and liabilities initially measured at fair value include certain assets and liabilities acquired in a business combination or through a non-monetary exchange transaction, intangible assets, goodwill, AROs, exit or disposal costs, and capital lease assets and liabilities where the present value of lease payments is greater than the fair value of the leased asset.

Revenues The Company's oil is sold primarily to marketers, gatherers, and refiners. Natural gas is sold primarily to interstate and intrastate natural-gas pipelines, direct end-users, industrial users, local distribution companies, and natural-gas marketers. NGLs are sold primarily to direct end-users, refiners, and marketers.

The Company recognizes sales revenues for oil, natural gas, and NGLs based on the amount of each product sold to purchasers when delivery to the purchaser has occurred and title has transferred. This occurs when product has been delivered to a pipeline or when a tanker lifting has occurred. The Company follows the sales method of accounting for natural-gas production imbalances. If the Company's sales volumes for a well exceed the Company's proportionate share of production from the well, a liability is recognized to the extent that the Company's share of estimated remaining recoverable reserves from the well is insufficient to satisfy this imbalance. No receivables are recorded for those wells on which the Company has taken less than its proportionate share of production.

Anadarko provides gathering, processing, treating, and transporting services pursuant to a variety of contracts. Under these arrangements, the Company receives fees, or retains a percentage of products or a percentage of the proceeds from the sale of products and recognizes revenue at the time services are performed or product is sold. These revenues are included in gathering, processing, and marketing sales in the Company's Consolidated Statements of Income.

Marketing margins related to the Company's production are included in oil, natural-gas, and NGLs sales. Marketing margins related to sales of commodities purchased from third parties and gains and losses on derivatives related to such marketing activities are included in gathering, processing, and marketing sales in the Company's Consolidated Statements of Income.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2016, 2015, AND 2014

1. Summary of Significant Accounting Policies (Continued)

The Company enters into buy/sell arrangements related to the transportation of a portion of its oil production. Under these arrangements, barrels are sold to a third party at a location-based contract price and subsequently repurchased by the Company at a downstream location. The difference in value between the sale and purchase price represents the transportation fee from the lease or certain gathering locations to more liquid markets. These arrangements are often required by private transporters. These transactions are reported on a net basis and included in oil and gas transportation in the Company's Consolidated Statements of Income.

Cash Equivalents The Company considers all highly liquid investments with a maturity of three months or less when purchased to be cash equivalents. The cash equivalents balance at December 31, 2016, includes commercial paper and investments in government money market funds in which the carrying value approximates fair value.

Accounts Receivable and Allowance for Uncollectible Accounts The Company conducts credit analyses of customers prior to making any sales to new customers or increasing credit for existing customers. Based on these analyses, the Company may require a standby letter of credit or a financial guarantee. The Company charges uncollectible accounts receivable against the allowance for uncollectible accounts when it determines collection will no longer be pursued.

Inventories Commodity inventories are stated at the lower of average cost or market.

Properties and Equipment Properties and equipment are stated at cost less accumulated DD&A. Costs of improvements that extend the lives of existing properties are capitalized. Maintenance and repairs are expensed as incurred. Upon retirement or sale, the cost of properties and equipment, net of the related accumulated DD&A, is removed and, if appropriate, gain or loss is recognized in gains (losses) on divestitures and other, net in the Company's Consolidated Statements of Income.

Oil and Gas Properties The Company applies the successful efforts method of accounting for oil and gas properties. Exploration costs, such as exploratory geological and geophysical costs, delay rentals, and exploration overhead, are charged against earnings as incurred. Exploratory drilling costs are initially capitalized pending the determination of proved reserves. If proved reserves are found, drilling costs remain capitalized and are classified as proved properties. For exploratory wells that find reserves that cannot be classified as proved when drilling is completed, costs continue to be capitalized as suspended exploratory drilling costs if there have been sufficient reserves found to justify completion as a producing well and sufficient progress is being made in assessing the reserves and the economic and operating viability of the project. At the end of each quarter, management reviews the status of all suspended exploratory drilling costs in light of ongoing exploration activities, in particular, whether the Company is making sufficient progress in its ongoing exploration and appraisal efforts or, in the case of discoveries requiring government sanctioning, analyzing whether development negotiations are underway and proceeding as planned. If management determines that future appraisal drilling or development activities are unlikely to occur, associated suspended exploratory well costs are expensed.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2016, 2015, AND 2014

1. Summary of Significant Accounting Policies (Continued)

Acquisition costs of unproved properties are periodically assessed for impairment and are transferred to proved properties to the extent the costs are associated with successful exploration activities. Significant undeveloped leases are assessed individually for impairment, based on the Company's current exploration plans, and a valuation allowance is provided if impairment is indicated. Unproved oil and gas properties with individually insignificant lease acquisition costs are amortized on a group basis (thereby establishing a valuation allowance) over the average lease terms at rates that provide for full amortization of unsuccessful leases upon lease expiration or abandonment. Costs of expired or abandoned leases are charged against the valuation allowance, while costs of productive leases are transferred to proved properties. Costs of maintaining and retaining unproved properties, as well as amortization of individually insignificant leases and impairment of unsuccessful leases, are included in exploration expense in the Company's Consolidated Statements of Income.

Capitalized Interest For significant projects, interest is capitalized as part of the historical cost of developing and constructing assets. Significant oil and gas investments in unproved properties, significant exploration and development projects that have not commenced production, significant midstream development activities that are in progress, and investments in equity-method affiliates that are undergoing the construction of assets that have not commenced principle operations qualify for interest capitalization. Interest is capitalized until the asset is ready for service. Capitalized interest is determined by multiplying the Company's weighted-average borrowing cost on debt by the average amount of qualifying costs incurred. Once an asset subject to interest capitalization is completed and placed in service, the associated capitalized interest is expensed through depreciation or impairment. See *Note 11—Debt and Interest Expense*.

Asset Retirement Obligations AROs associated with the retirement of tangible long-lived assets are recognized as liabilities with an increase to the carrying amounts of the related long-lived assets in the period incurred. The cost of the tangible asset, including the asset retirement cost, is depreciated over the useful life of the asset. AROs are recorded at estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligations discounted at the Company's credit-adjusted risk-free interest rate. Accretion expense is recognized over time as the discounted liabilities are accreted to their expected settlement value and is included in DD&A in the Company's Consolidated Statements of Income. If estimated future costs of AROs change, an adjustment is recorded to both the ARO and the long-lived asset. Revisions to estimated AROs can result from changes in retirement cost estimates, revisions to estimated inflation rates, and changes in the estimated timing of abandonment. See *Note 13—Asset Retirement Obligations*.

Impairments Properties and equipment are reviewed for impairment when facts and circumstances indicate that net book values may not be recoverable. In performing this review, an undiscounted cash flow test is performed at the lowest level for which identifiable cash flows are independent of cash flows from other assets. If the sum of the undiscounted future net cash flows is less than the net book value of the property, an impairment loss is recognized for the excess, if any, of the property's net book value over its estimated fair value. See *Note 5—Impairments*.

Depreciation, Depletion, and Amortization Costs of drilling and equipping successful wells, costs to construct or acquire facilities other than offshore platforms, associated asset retirement costs, and capital lease assets used in oil and gas activities are depreciated using the UOP method based on total estimated proved developed oil and gas reserves. Costs of acquiring proved properties, including leasehold acquisition costs transferred from unproved properties and costs to construct or acquire offshore platforms and associated asset retirement costs, are depleted using the UOP method based on total estimated proved developed and undeveloped reserves. Mineral properties are also depleted using the UOP method. All other properties are stated at historical acquisition cost, net of impairments, and are depreciated using the straight-line method over the useful lives of the assets, which range from 3 to 15 years for furniture and equipment, up to 40 years for buildings, and up to 47 years for gathering facilities.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2016, 2015, AND 2014

1. Summary of Significant Accounting Policies (Continued)

Goodwill and Other Intangible Assets Anadarko has allocated goodwill to the following reporting units: oil and gas exploration and production; WES gathering and processing; WES transportation; and other gathering and processing. Goodwill is subject to annual impairment testing in October (or more frequent testing as circumstances dictate). Anadarko's goodwill impairment test first assesses qualitative factors to determine whether goodwill is impaired. If the qualitative assessment indicates that it is more likely than not that the fair value of a reporting unit is less than its carrying amount, including goodwill, the Company will then perform a quantitative goodwill impairment test. Changes in goodwill may result from, among other things, impairments, acquisitions, or divestitures. See *Note 7—Goodwill and Other Intangible Assets*.

Other intangible assets represent contractual rights obtained in connection with business combinations that had favorable contractual terms relative to market at the acquisition date as well as customer-related intangible assets, including customer relationships established by acquired contracts. Other intangible assets are amortized over their estimated useful lives and are assessed for impairment whenever impairment indicators are present. See *Note 7—Goodwill and Other Intangible Assets*.

Derivative Instruments Anadarko uses derivative instruments to manage its exposure to cash-flow variability from commodity-price and interest-rate risks. Derivatives are carried on the balance sheet at fair value and are included in other current assets, other assets, accrued expenses, or other long-term liabilities, depending on the derivative position and the expected timing of settlement, unless they satisfy the normal purchases and sales exception criteria. Where the Company has the contractual right and intends to net settle, derivative assets and liabilities are reported on a net basis.

Gains and losses on derivative instruments are recognized currently in earnings. Net losses attributable to derivatives previously subject to hedge accounting reside in accumulated other comprehensive income (loss) and will be reclassified to earnings in future periods as the economic transactions to which the derivatives relate affect earnings. See *Note 9—Derivative Instruments*.

Accounts Payable Accounts payable included liabilities of $262 million at December 31, 2016, and $365 million at December 31, 2015, representing the amount by which checks issued, but not presented to the Company's banks for collection, exceeded balances in applicable bank accounts. Changes in these liabilities are reflected in cash flows from financing activities.

Legal Contingencies The Company is subject to legal proceedings, claims, and liabilities that arise in the ordinary course of business. Except for legal contingencies acquired in a business combination, which are recorded at fair value at the time of acquisition, the Company accrues losses associated with legal claims when such losses are probable and reasonably estimable. If the Company determines that a loss is probable and cannot estimate a specific amount for that loss, but can estimate a range of loss, the best estimate within the range is accrued. If no amount within the range is a better estimate than any other, the minimum amount of the range is accrued. Estimates are adjusted as additional information becomes available or circumstances change. Legal defense costs associated with loss contingencies are expensed in the period incurred. See *Note 16—Contingencies*.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2016, 2015, AND 2014

1. Summary of Significant Accounting Policies (Continued)

Environmental Contingencies The Company is subject to various environmental-remediation and reclamation obligations arising from federal, state, and local laws and regulations. Except for environmental contingencies acquired in a business combination, which are recorded at fair value at the time of acquisition, the Company accrues losses associated with environmental obligations when such losses are probable and reasonably estimable. Accruals for estimated environmental losses are recognized no later than at the time the remediation feasibility study, or the evaluation of response options, is complete. These accruals are adjusted as additional information becomes available or circumstances change. Future environmental expenditures are not discounted to their present value. Recoveries of environmental costs from other parties are recorded separately as assets at their undiscounted value when receipt of such recoveries is probable. See *Note 16—Contingencies*.

Noncontrolling Interests Noncontrolling interests represent third-party ownership in the net assets of the Company's consolidated subsidiaries and are presented as a component of equity. Changes in Anadarko's ownership interests in subsidiaries that do not result in deconsolidation are recognized in equity. See *Note 22—Noncontrolling Interests*.

Income Taxes The Company files various U.S. federal, state, and foreign income tax returns. Deferred federal, state, and foreign income taxes are provided on temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax basis. The Company routinely assesses the realizability of its deferred tax assets. If the Company concludes that it is more likely than not that some of the deferred tax assets will not be realized, the tax asset is reduced by a valuation allowance. The Company recognizes a tax benefit from an uncertain tax position when it is more likely than not that the position will be sustained upon examination, based on the technical merits of the position. The tax benefit recorded is equal to the largest amount that is greater than 50% likely to be realized through final settlement with a taxing authority. Interest and penalties related to unrecognized tax benefits are recognized in income tax expense (benefit). The Company uses the flow-through method to account for its investment tax credits. See *Note 12—Income Taxes*.

Share-Based Compensation The Company accounts for share-based compensation at fair value. The Company grants equity-classified awards, including stock options and non-vested equity shares (restricted stock awards and units). The Company may also grant equity-classified and liability-classified awards based on a comparison of the Company's TSR to the TSR of a predetermined group of peer companies (performance units).

The fair value of stock option awards is determined using the Black-Scholes option-pricing model. Restricted stock awards and units are valued using the market price of Anadarko common stock. For other share-based compensation awards, fair value is determined using a Monte Carlo simulation.

The Company records compensation cost, net of estimated forfeitures, for share-based compensation awards over the requisite service period using the straight-line method. An adjustment is made to compensation cost for any difference between the estimated forfeitures and the actual forfeitures related to the awards. For equity-classified share-based compensation awards, expense is recognized based on the grant-date fair value. For liability-classified share-based compensation awards, expense is recognized for those awards expected to ultimately be paid. The amount of expense reported for liability-classified awards is adjusted for fair-value changes so that the expense recognized for each award is equivalent to the amount to be paid. See *Note 21—Share-Based Compensation*.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2016, 2015, AND 2014

1. Summary of Significant Accounting Policies (Continued)

Recently Adopted Accounting Standards ASU 2017-04, *Intangibles—Goodwill and Other (Topic 350)*, eliminates Step 2 from the goodwill impairment test in an effort to simplify the subsequent measurement of goodwill. This ASU is effective for annual and interim periods beginning in 2020 and is required to be adopted using a prospective approach, with early adoption permitted for goodwill impairment tests performed after January 1, 2017. The Company adopted this ASU on January 1, 2017, and it will only be applicable to the extent that the Company determines its goodwill is impaired.

ASU 2017-01, *Business Combinations (Topic 805): Clarifying the Definition of a Business* assists in determining whether a transaction should be accounted for as an acquisition or disposal of assets or as a business. This ASU provides a screen that when substantially all of the fair value of the gross assets acquired, or disposed of, are concentrated in a single identifiable asset, or a group of similar identifiable assets, the set will not be considered a business. If the screen is not met, a set must include an input and a substantive process that together significantly contribute to the ability to create an output to be considered a business. This ASU is effective for annual and interim periods beginning in 2018 and is required to be adopted using a prospective approach, with early adoption permitted for transactions not previously reported in issued financial statements. The Company adopted this ASU on January 1, 2017, and expects that the adoption of this ASU could have a material impact on future consolidated financial statements as goodwill would not be allocated to divestitures or recorded for acquisitions that are not considered to be businesses.

ASU 2016-16, *Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other Than Inventory* requires an entity to recognize the income tax consequences of an intra-entity transfer of an asset other than inventory when the transfer occurs and eliminates the exception for an intra-entity transfer of an asset other than inventory. This ASU is effective for annual and interim periods beginning in 2018 and is required to be adopted using a modified retrospective approach, with early adoption permitted. The Company adopted this ASU on January 1, 2017, and will recognize a cumulative adjustment to retained earnings of $31 million during the first quarter of 2017.

ASU 2016-09, *Compensation—Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting* simplifies the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, classification on the statement of cash flows, and accounting for forfeitures. The Company adopted this ASU on January 1, 2017, and it will not have a material impact on the Company's future consolidated financial statements.

ASU 2015-03, *Interest—Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* and ASU 2015-15, *Interest—Imputation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements* require capitalized debt issuance costs, except for those related to revolving credit facilities, to be presented in the balance sheet as a direct deduction from the carrying amount of the related debt liability, rather than as an asset. The Company adopted these ASUs on January 1, 2016, using a retrospective approach. The adoption resulted in a reclassification that reduced other current assets and short-term debt by $1 million and reduced other assets and long-term debt by $82 million on the Company's Consolidated Balance Sheet at December 31, 2015.

ASU 2015-02, *Consolidation (Topic 810): Amendments to the Consolidation Analysis* was adopted on January 1, 2016. In accordance with the new ASU, WGP and WES are considered VIEs for which the Company is the primary beneficiary. Prior to adoption of the ASU, WGP and WES were consolidated by the Company under the voting interest model. After adoption, WGP and WES were consolidated by the Company under the variable interest model. While this ASU requires additional financial statement disclosure, it has no impact on the Company's consolidated results of operations, cash flows, or financial position. See *Note 23—Variable Interest Entities*.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2016, 2015, AND 2014

1. Summary of Significant Accounting Policies (Continued)

New Accounting Standards Issued But Not Yet Adopted ASU 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash* requires an entity to explain the changes in the total of cash, cash equivalents, restricted cash, and restricted cash equivalents on the statement of cash flows and to provide a reconciliation of the totals in that statement to the related captions in the balance sheet when the cash, cash equivalents, restricted cash, and restricted cash equivalents are presented in more than one line item on the balance sheet. This ASU is effective for annual and interim periods beginning after December 15, 2017, and is required to be adopted using a retrospective approach, with early adoption permitted. The Company is evaluating the impact of the adoption of this ASU on its consolidated financial statements.

ASU 2016-15, *Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments* provides clarification on how certain cash receipts and cash payments are presented and classified on the statement of cash flows. This ASU is effective for annual and interim periods beginning after December 15, 2017, and is required to be adopted using a retrospective approach if practicable, with early adoption permitted. The Company does not expect the adoption of this ASU to have a material impact on its Consolidated Statement of Cash Flows.

ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)* supersedes current revenue recognition requirements and industry-specific guidance. The codification requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services. Additional disclosures will be required to describe the nature, amount, timing and uncertainty of revenue and cash flows from contracts with customers. The Company has completed an initial review of contracts in each of its revenue streams and is developing accounting policies to address the provisions of the ASU. While the Company does not currently expect net earnings to be materially impacted, the Company is currently analyzing whether total revenues and total expenses may increase as a result of recognizing both revenue for noncash consideration for services provided by our midstream business and revenue and associated cost of product for the subsequent sale of commodities received as such noncash consideration. Anadarko continues to evaluate the impact of this and other provisions of the ASU on its accounting policies, internal controls, and consolidated financial statements and related disclosures, and has not finalized any estimates of the potential impacts. The Company will adopt the new standard on January 1, 2018, using the modified retrospective method with a cumulative adjustment to retained earnings.

ASU 2016-02, *Leases (Topic 842)* requires lessees to recognize a lease liability and a right-of-use asset for all leases, including operating leases, with a term greater than 12 months on the balance sheet. The provisions of ASU 2016-02 also modify the definition of a lease and outline the requirements for recognition, measurement, presentation, and disclosure of leasing arrangements by both lessees and lessors. This ASU is effective for annual and interim periods beginning after December 15, 2018. The Company is currently analyzing its portfolio of contracts to assess the impact future adoption of this ASU may have on its consolidated financial statements.

2. Inventories

The following summarizes the major classes of inventories included in other current assets at December 31:

millions	**2016**	2015
Oil	**$ 169**	$ 116
Natural gas	**38**	36
NGLs	**106**	64
Total inventories	**$ 313**	$ 216

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2016, 2015, AND 2014

3. Acquisitions, Divestitures, and Assets Held for Sale

Acquisitions On December 15, 2016, the Company closed the GOM Acquisition for $1.8 billion using a portion of the net proceeds from the September 2016 issuance of 40.5 million shares of its common stock. This acquisition constitutes a business combination and was accounted for using the acquisition method of accounting. This acquisition expanded Anadarko's operated infrastructure and tie-back inventory, more than doubled the Company's ownership in the Lucius development to approximately 49%, and doubled its net production from the Gulf of Mexico. The following summarizes the preliminary fair value of assets acquired and liabilities assumed at the acquisition date, pending customary closing adjustments and valuation adjustments:

millions	
Current assets	$ 8
Properties and equipment	2,471
Other assets	145
AROs	(813)
Net assets acquired	$ 1,811
Accounts receivable	91
Accounts payable	(5)
Other long-term liabilities	(98)
Cash paid at closing	$ 1,799

Fair-value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and thus represent Level 3 inputs. The fair value of properties and equipment is primarily based on income and cost approaches. As part of the acquisition, Anadarko agreed to pay the seller, on a quarterly basis, a proportionate amount of gross proceeds from a certain contract until the amount paid equals approximately $150 million. The fair value of the contingent consideration of $103 million was estimated using the income approach and is included in accounts payable and other long-term liabilities in the table above. The assets acquired and liabilities assumed are included within the oil and gas exploration and production reporting segment. Results of operations attributable to the acquisition are included in the Company's Consolidated Statements of Income from the acquisition date and are not material to the Company's Consolidated Statements of Income.

The following summarizes the unaudited pro forma condensed financial information of the Company as if the acquisition had occurred on January 1, 2015:

millions	**2016**	**2015**
Revenues	$ 8,849	$ 9,786
Net income (loss)	(2,623)	(6,560)

The unaudited pro forma information is presented for illustration purposes only and is not necessarily indicative of the operating results that would have occurred had the acquisition been completed at January 1, 2015, nor is it necessarily indicative of future operating results of the combined entity. The pro forma information includes adjustments for revenues and direct expenses based on historical results of the acquired assets and DD&A based on the purchase price allocated to property, plant, and equipment and estimated useful lives. Adjustments are not included for the acquired assets' historical property impairments as they were made under the full cost method of accounting. The pro forma adjustments include estimates and assumptions based on currently available information. Management believes the estimates and assumptions are reasonable, and the relative effects of the transaction are properly reflected. The unaudited pro forma information does not reflect any cost savings anticipated as a result of the acquisition or any future acquisition related expenses.

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3. Acquisitions, Divestitures, and Assets Held for Sale (Continued)

Property Exchange In February 2017, WES entered into an agreement with a third party whereby WES will acquire the third party's 50% nonoperated interest in the DBJV system in exchange for (a) WES's 33.75% interest in nonoperated Marcellus midstream assets and (b) $155 million in cash. WES currently holds a 50% interest in, and operates, the DBJV system. WES expects to fund the cash consideration through borrowings under the WES RCF and to close the transaction, subject to standard closing conditions and adjustments, in the first quarter of 2017.

Divestitures and Assets Held for Sale The following summarizes the proceeds received and gains (losses) recognized on divestitures and assets held for sale for the years ended December 31:

millions	**2016**	2015	2014
Proceeds received, net of closing adjustments	**$ 2,356**	$ 1,415	$ 4,968
Gains (losses) on divestitures, net [(1)]	**(757)**	(1,022)	1,891

(1) Includes goodwill allocated to divestitures of $397 million in 2016, $184 million in 2015, and $152 million in 2014.

2016 During the year ended December 31, 2016, the Company's divestitures were primarily related to the following U.S. onshore assets:

- certain East Texas/Louisiana assets in the oil and gas exploration and production and midstream reporting segments for net proceeds of $1.0 billion and a net loss of $439 million
- certain Kansas assets in the oil and gas exploration and production and midstream reporting segments for net proceeds of $159 million and a loss of $4 million
- certain East Texas assets in the oil and gas exploration and production and midstream reporting segments for net proceeds of $89 million and a loss of $64 million
- certain West Texas assets in the oil and gas exploration and production and midstream reporting segments for net proceeds of $221 million and a loss of $52 million
- certain Wyoming assets in the oil and gas exploration and production reporting segment for net proceeds of $588 million and a loss of $58 million

Losses on assets held for sale are included in gains (losses) on divestitures and other, net in the Company's Consolidated Statements of Income. Certain Marcellus U.S. onshore assets located in Pennsylvania included in the oil and gas exploration and production and midstream reporting segments satisfied criteria to be considered held for sale during the fourth quarter of 2016, at which time the Company remeasured these assets to their current fair value using a market approach and Level 2 fair-value measurement and recognized a loss of $129 million. The sale of these assets is expected to close in the first quarter of 2017. At December 31, 2016, the Company's Consolidated Balance Sheet included long-term assets of $1.2 billion, which includes $193 million of goodwill, and long-term liabilities of $66 million associated with assets held for sale.

In January 2017, the Company entered into an agreement to sell certain Eagleford U.S. onshore assets located in South Texas included in the oil and gas exploration and production reporting segment for $2.3 billion. The transaction is expected to close during the first quarter of 2017.

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3. Acquisitions, Divestitures, and Assets Held for Sale (Continued)

2015 During the year ended December 31, 2015, the Company's divestitures were primarily related to the following U.S. onshore assets:

- certain coalbed methane assets in the oil and gas exploration and production and midstream reporting segments for net proceeds of $154 million and a loss of $538 million
- certain assets in the oil and gas exploration and production and midstream reporting segments in East Texas for net proceeds of $425 million and a loss of $110 million
- certain EOR assets in the oil and gas exploration and production reporting segment for net proceeds of $675 million and a loss of $350 million, in addition to the loss recognized in 2014 when the asset was originally held for sale as discussed below

2014 During the year ended December 31, 2014, the Company's divestitures primarily related to the following assets included in the oil and gas exploration and production reporting segment:

- a 10% working interest in Offshore Area 1 in Mozambique for $2.64 billion and a gain of $1.5 billion
- a Chinese subsidiary for $1.075 billion and a gain of $510 million
- interest in the nonoperated Vito deepwater development, along with several surrounding exploration blocks in the Gulf of Mexico, for $500 million and a gain of $237 million
- interest in the Pinedale/Jonah assets in Wyoming for $581 million

During the fourth quarter of 2014, Anadarko considered certain U.S. onshore EOR assets to be held for sale and recognized losses of $456 million. These assets were remeasured to their fair value using a market approach and Level 2 fair-value measurement. Due to a reduced probability that the assets would be sold within one year, the assets were no longer considered held for sale at December 31, 2014.

4. Properties and Equipment

The following summarizes properties and equipment by segment at December 31:

millions	**2016**	2015
Oil and gas exploration and production [(1)]	**$ 57,581**	$ 59,389
Midstream	**8,613**	8,458
Other	**2,819**	2,836
Gross properties and equipment	**$ 69,013**	$ 70,683
Less accumulated DD&A	**36,845**	36,932
Net properties and equipment	**$ 32,168**	$ 33,751

(1) Includes costs associated with unproved properties of $4.1 billion at December 31, 2016, and $3.5 billion at December 31, 2015.

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5. Impairments

Impairments of Long-Lived Assets Impairments of long-lived assets are included in impairment expense in the Company's Consolidated Statements of Income. The following summarizes impairments of long-lived assets and the related post-impairment fair values by segment at December 31:

	2016		2015		2014	
millions	**Impairment**	**Fair Value** [(1)]	Impairment	Fair Value [(1)]	Impairment	Fair Value [(1)]
Oil and gas exploration and production						
U.S. onshore properties	**$ 28**	**$ 617**	$ 3,684	$ 1,253	$ 545	$ 552
Gulf of Mexico properties	**27**	**61**	349	65	276	223
Cost-method investment [(2)]	**59**	**—**	3	59	3	62
Midstream	**73**	**32**	1,039	212	12	—
Other	**40**	**—**	—	—	—	—
Total impairments	**$ 227**	**$ 710**	$ 5,075	$ 1,589	$ 836	$ 837

(1) Measured as of the impairment date using the income approach and Level 3 inputs.
(2) The after-tax net investment fair value was $32 million at December 31, 2015 and 2014.

2016 Impairments were primarily related to the uncertain recovery of the Company's Venezuelan cost-method investment, negative developments related to commercial negotiations of a certain midstream asset, impairment of an office building, changes in development plans for certain U.S. onshore oil and gas assets, and a reduction in estimated future cash flows related to an oil and gas property in the Gulf of Mexico.

2015 Impairments were primarily related to the Company's Greater Natural Buttes oil and gas and midstream properties, certain other U.S. onshore oil and gas and midstream properties, and oil and gas properties in the Gulf of Mexico, all of which were impaired due to lower forecasted commodity prices.

2014 Certain U.S. onshore and Gulf of Mexico oil and gas properties were impaired primarily due to lower forecasted commodity prices.

Impairments of Unproved Properties Impairments of unproved properties are included in exploration expense in the Company's Consolidated Statements of Income. In 2016, the Company recognized a $72 million impairment of unproved properties in the Gulf of Mexico and $92 million of unproved international properties primarily in Brazil and Tunisia due to the Company's current intentions to not pursue future exploration activities. In 2015, the Company recognized a $935 million impairment of unproved Greater Natural Buttes properties and a $66 million impairment of an unproved Gulf of Mexico property as a result of lower commodity prices. Also in 2015, the Company recognized a $109 million impairment of unproved Utica properties resulting from an assignment of mineral interests in settlement of a legal matter.

Potential for Future Impairments At December 31, 2016, the Company's estimate of undiscounted future cash flows attributable to a certain international asset group with a net book value of approximately $1.3 billion indicated that the carrying amount was expected to be recovered; however, this asset group may be at risk for impairment if the estimates of future cash flows decline. The Company estimates that a 10% decline in oil prices (with all other assumptions unchanged) could result in a non-cash impairment in excess of $550 million for the asset group. It is also reasonably possible that significant declines in commodity prices, further changes to the Company's drilling plans in response to lower prices, or increases in drilling or operating costs could result in other additional impairments.

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6. Suspended Exploratory Well Costs

The following summarizes the changes in suspended exploratory well costs at December 31 for each of the last three years. Additions pending the determination of proved reserves excludes amounts capitalized and subsequently charged to expense within the same year.

millions	**2016**	2015	2014
Balance at January 1	**$ 1,124**	$ 1,522	$ 2,232
Additions pending the determination of proved reserves	**490**	461	421
Divestitures and other [1]	**(11)**	(33)	(913)
Reclassifications to proved properties	**(50)**	(104)	(100)
Charges to exploration expense [2] [3] [4]	**(323)**	(722)	(118)
Balance at December 31	**$ 1,230**	$ 1,124	$ 1,522

(1) Includes $(744) million during 2014 related to the Company's sale of a 10% working interest in Offshore Area 1 in Mozambique.

(2) Includes $(565) million during 2015 related to Brazil. The Company does not expect to have substantive exploration and development activities in Brazil in the foreseeable future.

(3) Includes $(92) million during 2016 related to Mozambique. The Tubarão Tigre discovery wells were expensed based on the outlook for development viability, the commodity market conditions, and the complexity introduced by the depth and characteristics of the reservoir. The Orca-4 well was expensed after additional reservoir analysis and the determination that the well was not associated with the first three Orca wells.

(4) Includes $(231) million during 2016 for the Gulf of Mexico primarily related to the Yeti project, as the Company does not expect to have exploration activities on this prospect in the foreseeable future, and a Shenandoah well that was expensed, as it was no longer reasonably possible that the wellbore could be used in the development of the project, if a final investment decision is reached.

The following provides an aging of suspended well balances at December 31:

millions	**2016**	2015	2014
Exploratory well costs capitalized for a period of one year or less	**$ 460**	$ 452	$ 393
Exploratory well costs capitalized for a period greater than one year	**770**	672	1,129
Balance at December 31	**$ 1,230**	$ 1,124	$ 1,522

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6. Suspended Exploratory Well Costs (Continued)

The following summarizes a further aging by geographic area of those exploratory well costs that have been capitalized for a period greater than one year since the completion of drilling at December 31, 2016:

millions except projects	Number of Projects	Total	2015	2014	2013 and prior
U.S. Onshore	15	$ 58	$ 12	$ 25	$ 21
U.S. Offshore	3	296	86	13	197
International	5	416	184	49	183
	23	$ 770	$ 282	$ 87	$ 401

Projects with suspended exploratory well costs include wells that have sufficient reserves to justify completion as a producing well and sufficient progress is being made in assessing the reserves and the economic and operating viability of the project. Suspended exploratory well costs capitalized for a period greater than one year after completion of drilling at December 31, 2016, primarily related to the Gulf of Mexico, Ghana, Colombia, Mozambique, and Côte d'Ivoire.

Gulf of Mexico Exploratory well costs are primarily related to the Shenandoah discovery and have been suspended pending further appraisal activities, including drilling and analysis of well results. Appraisal activities undertaken at the Shenandoah discovery include the acquisition of core and pressure data across the primary reservoir interval, the processing and analysis of seismic data, reservoir simulation modeling, and analysis of well results. Remaining activities required to classify the associated reserves as proved for the Shenandoah discovery include completion of geologic, reservoir, and economic modeling; the drilling of additional wells to test the structure; product development testing; and pre-front end engineering and design (FEED) and FEED engineering studies.

Ghana Exploratory well costs are suspended pending development plan approval. During the fourth quarter of 2015, the Company and its partners submitted the Jubilee full field development plan to include the Mahogany East and Teak areas, and work is ongoing to gain government approval. Remaining activities required to classify the associated reserves as proved include approval of development plans and project sanctioning.

Colombia Exploratory well costs are related to the Kronos discovery. Well costs have been suspended pending ongoing appraisal activities, including analysis of well results and geologic and geophysical studies. Remaining activities required to classify the associated reserves as proved for the Kronos discovery include additional exploratory and appraisal drilling, geologic and geophysical studies, reservoir modeling and simulation, economic modeling, pre-development studies, approval of development plans, and project sanctioning.

Mozambique Exploratory well costs are primarily related to the Golfinho-Atum discovery and have been suspended pending a final investment decision (FID). The Company is progressing three elements that will position the project to take FID: the legal and contractual framework to develop LNG in Mozambique, project finance, and long-term LNG sales contracts. During the fourth quarter of 2016, the Company and its partners submitted the Golfinho-Atum Development Plan to the Government of Mozambique. Approval of the Development Plan and conclusion of the three elements discussed above are required to achieve an affirmative FID and classify the associated reserves as proved.

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6. Suspended Exploratory Well Costs (Continued)

Côte d'Ivoire Exploratory well costs are related to the Paon discovery and have been suspended pending further appraisal activities. Appraisal activities at Paon in 2016 included drilling a successful horizontal appraisal well at the Paon-5A, successfully drilling a horizontal sidetrack at the Paon-3AR, and performing a drillstem and interference testing program. Additional activities included the analysis of well results and integration into reservoir simulation modeling. Remaining activities required to classify the associated reserves as proved for the Paon discovery include further appraisal drilling; continued geologic, reservoir, and economic modeling; FEED studies; approval of development plans; and project sanctioning.

If additional information becomes available that raises substantial doubt as to the economic or operational viability of any of these projects, the associated costs will be expensed at that time.

7. Goodwill and Other Intangible Assets

Goodwill At December 31, 2016, the Company had \$5.0 billion of goodwill allocated to the following reporting units: \$4.6 billion to oil and gas exploration and production, \$413 million to WES gathering and processing, \$5 million to WES transportation, and \$32 million to other gathering and processing. During 2016, goodwill decreased \$395 million primarily related to asset divestitures. See *Note 3—Acquisitions, Divestitures, and Assets Held for Sale*. The Company's 2016 annual qualitative impairment assessment of goodwill indicated no impairment.

Other Intangible Assets Intangible assets and associated amortization expense were as follows at December 31:

millions	**2016**	2015
Gross carrying amount	**$ 1,013**	$ 1,013
Accumulated amortization	**(109)**	(77)
Net carrying amount	**$ 904**	$ 936
Amortization expense	**$ 32**	$ 33

Intangible assets are primarily related to customer contracts associated with WES's 2014 acquisition of DBM (previously Nuevo). These contracts are being amortized over 30 years. The annual aggregate amortization expense for intangible assets is expected to be \$31 million each of the next five years.

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8. Equity-Method Investments

In 2007, Anadarko contributed certain of its oil and gas properties and gathering and processing assets, with an aggregate fair value of $2.9 billion at the time of the contribution, to newly formed unconsolidated entities in exchange for noncontrolling mandatorily redeemable LIBOR-based preferred interests in those entities. The common equity of the investee entities is 95% owned by third parties that also maintain control over the assets. Subsequent to their formation, the investee entities loaned Anadarko an aggregate of $2.9 billion, each with a 35-year term. The Company accounts for its investment in these entities using the equity method of accounting. The carrying amount of these investments was $2.8 billion and the carrying amount of notes payable to affiliates was $2.9 billion at December 31, 2016. Anadarko's noncontrolling interest may be redeemed beginning in 2022 by Anadarko or the owner of the controlling interest. Anadarko's interest is mandatorily redeemable in 2037. Anadarko has legal right of setoff and intends to net settle its obligations under each of the notes payable to the investees with the distributable value of its interest in the corresponding investee. Accordingly, the investment for each entity and the related obligation are presented net on the Company's Consolidated Balance Sheets. Other long-term liabilities—other included $48 million at December 31, 2016, and $43 million at December 31, 2015, and other assets included $2 million at December 31, 2016 and 2015, related to these investments.

Interest on the notes issued by Anadarko is variable, and is equivalent to LIBOR plus a spread that fluctuates with Anadarko's credit rating. The applicable interest rate was 1.96% at December 31, 2016, and 1.51% at December 31, 2015. The note payable agreement contains a quarterly covenant that provides for a maximum Anadarko debt-to-capital ratio of 67% (excluding the effect of non-cash write-downs). Anadarko was in compliance with this covenant at December 31, 2016. Other (income) expense, net includes interest expense on the notes payable of $49 million in 2016, $37 million in 2015, and $36 million in 2014, and equity (earnings) losses from Anadarko's investments in the investee entities of $(33) million in 2016, $15 million in 2015, and $(45) million in 2014.

9. Derivative Instruments

Objective and Strategy The Company uses derivative instruments to manage its exposure to cash-flow variability from commodity-price and interest-rate risks. Futures, swaps, and options are used to manage exposure to commodity-price risk inherent in the Company's oil and natural-gas production and natural-gas processing operations (Oil and Natural-Gas Production/Processing Derivative Activities). Futures contracts and commodity-price swap agreements are used to fix the price of expected future oil and natural-gas sales at major industry trading locations such as Cushing, Oklahoma or Sullom Voe, Scotland for oil and Henry Hub, Louisiana for natural gas. Basis swaps are periodically used to fix or float the price differential between product prices at one market location versus another. Options are used to establish a floor price, a ceiling price, or a floor and a ceiling price (collar) for expected future oil and natural-gas sales. Derivative instruments are also used to manage commodity-price risk inherent in customer price requirements and to fix margins on the future sale of natural gas and NGLs from the Company's leased storage facilities (Marketing and Trading Derivative Activities).

Interest-rate swaps are used to fix or float interest rates on existing or anticipated indebtedness. The purpose of these instruments is to manage the Company's existing or anticipated exposure to interest-rate changes. The fair value of the Company's current interest-rate swap portfolio is subject to changes in interest rates.

The Company does not apply hedge accounting to any of its derivative instruments. As a result, gains and losses associated with derivative instruments are recognized currently in earnings. Net derivative losses attributable to derivatives previously subject to hedge accounting reside in accumulated other comprehensive income (loss) and are reclassified to earnings as the transactions to which the derivatives relate are recognized in earnings. See *Note 20—Accumulated Other Comprehensive Income (Loss)*.

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9. Derivative Instruments (Continued)

Oil and Natural-Gas Production/Processing Derivative Activities The oil prices listed below are a combination of NYMEX West Texas Intermediate and Intercontinental Exchange, Inc. (ICE) Brent Blend prices. The natural-gas prices listed below are NYMEX Henry Hub prices. The NGLs prices listed below are Oil Price Information Services prices. The following is a summary of the Company's derivative instruments related to oil and natural-gas production/processing derivative activities at December 31, 2016:

	2017 Settlement	2018 Settlement
Oil		
Three-Way Collars (MBbls/d)	91	—
Average price per barrel		
Ceiling sold price (call)	$ 59.80	$ —
Floor purchased price (put)	$ 50.00	$ —
Floor sold price (put)	$ 40.00	$ —
Natural Gas		
Three-Way Collars (thousand MMBtu/d)	682	250
Average price per MMBtu		
Ceiling sold price (call)	$ 3.60	$ 3.54
Floor purchased price (put)	$ 2.75	$ 2.75
Floor sold price (put)	$ 2.00	$ 2.00
Fixed-Price Contracts (thousand MMBtu/d)	37	—
Average price per MMBtu	$ 3.23	$ —
NGLs		
Fixed-Price Contracts (MBbls/d)	2	—
Average price per barrel	$ 15.84	$ —

A three-way collar is a combination of three options: a sold call, a purchased put, and a sold put. The sold call establishes the maximum price that the Company will receive for the contracted commodity volumes. The purchased put establishes the minimum price that the Company will receive for the contracted volumes unless the market price for the commodity falls below the sold put strike price, at which point the minimum price equals the reference price (e.g., NYMEX) plus the excess of the purchased put strike price over the sold put strike price.

Marketing and Trading Derivative Activities The Company had financial derivative transactions with notional volumes of natural gas totaling 2 Bcf at December 31, 2016, and 8 Bcf at December 31, 2015, that were entered into to mitigate commodity-price risk related to fixed-price purchase and sales contracts and storage activity.

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9. Derivative Instruments (Continued)

Interest-Rate Derivatives Anadarko has outstanding interest-rate swap contracts to manage interest-rate risk associated with anticipated debt issuances. The Company has locked in a fixed interest rate in exchange for a floating interest rate indexed to the three-month LIBOR.

In 2015, the Company extended the reference-period start dates and amended the mandatory termination dates on certain interest-rate swaps so that, at the start of the reference period, Anadarko will receive quarterly payments based on the floating rate and make semi-annual payments based on the fixed interest rate. The interest-rate swaps are required to be settled in full at the mandatory termination date. As part of these interest-rate swap modifications, the fixed interest rates on the swaps were also adjusted, and the Company recognized a loss of $137 million, which is included in gains (losses) on derivatives, net in the Company's Consolidated Statement of Income, and increased the related derivative liability. In February 2016, in exchange for amended terms with certain counterparties, the Company modified the mandatory termination dates from 2021 to 2018 and, in some cases, the related fixed interest rates on interest-rate swaps with an aggregate notional principal amount of $500 million.

At December 31, 2016, the Company had outstanding interest-rate swaps with a notional amount of $1.6 billion due prior to or at September 2021 that will manage interest-rate risk associated with the potential refinancing of the Company's $900 million Senior Notes due 2019 and the Zero Coupons, should the Zero Coupons be put to the Company prior to the swap termination dates. At the next put date in October 2017, the accreted value of the Zero Coupons will be $883 million. See *Note 11—Debt and Interest Expense*. Depending on market conditions, liability-management actions, or other factors, the Company may enter into offsetting interest-rate swap positions or settle or amend certain or all of the currently outstanding interest-rate swaps.

Derivative settlements and collateralization are classified as cash flows from operating activities unless the derivatives contain an other-than-insignificant financing element, in which case the settlements and collateralization are classified as cash flows from financing activities. As a result of prior extensions of reference-period start dates without settlement of the related interest-rate derivative obligations, the interest-rate derivatives in the Company's portfolio contain an other-than-insignificant financing element, and therefore, any settlements or collateralization related to these extended interest-rate derivatives are classified as cash flows from financing activities. Interest-rate swap agreements were settled for total cash payments of $266 million in 2016 and $222 million in 2014.

The Company had the following outstanding interest-rate swaps at December 31, 2016:

millions except percentages			Mandatory	Weighted-Average
Notional Principal Amount		**Reference Period**	**Termination Date**	**Interest Rate**
$	500	September 2016 – 2046	September 2018	6.559%
$	300	September 2016 – 2046	September 2020	6.509%
$	450	September 2017 – 2047	September 2018	6.445%
$	100	September 2017 – 2047	September 2020	6.891%
$	250	September 2017 – 2047	September 2021	6.570%

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9. Derivative Instruments (Continued)

Effect of Derivative Instruments—Balance Sheet The following summarizes the fair value of the Company's derivative instruments at December 31:

millions	Gross Derivative Assets		Gross Derivative Liabilities	
Balance Sheet Classification	**2016**	2015	**2016**	2015
Commodity derivatives				
Other current assets	**$ 10**	$ 462	**$ (3)**	$ (177)
Other assets	**9**	8	**—**	—
Accrued expenses	**66**	—	**(201)**	(3)
Other liabilities	**—**	—	**(12)**	—
	85	470	**(216)**	(180)
Interest-rate derivatives				
Other current assets	**8**	2	**—**	—
Other assets	**23**	54	**—**	—
Accrued expenses	**—**	—	**(48)**	(54)
Other liabilities	**—**	—	**(1,328)**	(1,488)
	31	56	**(1,376)**	(1,542)
Total derivatives	**$ 116**	$ 526	**$ (1,592)**	$ (1,722)

Effect of Derivative Instruments—Statement of Income The following summarizes gains and losses related to derivative instruments:

millions			
Classification of (Gain) Loss Recognized	**2016**	2015	2014
Commodity derivatives			
Gathering, processing, and marketing sales [(1)]	**$ 6**	$ (1)	$ 10
(Gains) losses on derivatives, net	**147**	(367)	(589)
Interest-rate derivatives			
(Gains) losses on derivatives, net	**139**	268	786
Total (gains) losses on derivatives, net	**$ 292**	$ (100)	$ 207

(1) Represents the effect of Marketing and Trading Derivative Activities.

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9. Derivative Instruments (Continued)

Credit-Risk Considerations The financial integrity of exchange-traded contracts, which are subject to nominal credit risk, is assured by NYMEX or ICE through systems of financial safeguards and transaction guarantees. Over-the-counter traded swaps, options, and futures contracts expose the Company to counterparty credit risk. The Company monitors the creditworthiness of its counterparties, establishes credit limits according to the Company's credit policies and guidelines and assesses the impact on the fair value of its counterparties' creditworthiness. The Company has the ability to require cash collateral or letters of credit to mitigate its credit-risk exposure.

The Company has netting agreements with financial institutions that permit net settlement of gross commodity derivative assets against gross commodity derivative liabilities and routinely exercises its contractual right to offset gains and losses when settling with derivative counterparties. In addition, the Company has setoff agreements with certain financial institutions that may be exercised in the event of default and provide for contract termination and net settlement across derivative types.

The Company's derivative instruments are subject to individually negotiated credit provisions that may require collateral of cash or letters of credit depending on the derivative's portfolio valuation versus negotiated credit thresholds. These credit thresholds may also require full or partial collateralization or immediate settlement of the Company's obligations if certain credit-risk-related provisions are triggered, such as if the Company's credit rating from major credit rating agencies declines to a level that is below investment grade. In February 2016, Moody's downgraded the Company's long-term debt credit rating from investment grade (Baa2) to below investment grade (Ba1). The downgrade triggered credit-risk-related features with certain derivative counterparties and required the Company to post collateral under its derivative instruments. During the third quarter of 2016, Anadarko negotiated the increase of a credit threshold for an interest-rate derivative. As a result of the increased credit threshold, $200 million of collateral was returned to the Company. No counterparties have requested termination or full settlement of derivative positions. The aggregate fair value of derivative instruments with credit-risk-related contingent features for which a net liability position existed was $1.4 billion (net of $117 million of collateral) at December 31, 2016, and $1.3 billion (net of $58 million of collateral) at December 31, 2015.

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9. Derivative Instruments (Continued)

Fair Value Fair value of futures contracts is based on unadjusted quoted prices in active markets for identical assets or liabilities, which represent Level 1 inputs. Valuations of physical-delivery purchase and sale agreements, over-the-counter financial swaps, and commodity option collars are based on similar transactions observable in active markets and industry-standard models that primarily rely on market-observable inputs. Inputs used to estimate fair value in industry-standard models are categorized as Level 2 inputs, because substantially all assumptions and inputs are observable in active markets throughout the full term of the instruments. Inputs used to estimate the fair value of swaps and options include market-price curves; contract terms and prices; credit-risk adjustments; and, for Black-Scholes option valuations, discount factors and implied market volatility.

The following summarizes the fair value of the Company's derivative assets and liabilities, by input level within the fair-value hierarchy:

millions	Level 1	Level 2	Level 3	Netting [(1)]	Collateral	Total
December 31, 2016						
Assets						
Commodity derivatives	$ 2	$ 83	$ —	$ (69)	$ —	$ 16
Interest-rate derivatives	—	31	—	—	—	31
Total derivative assets	$ 2	$ 114	$ —	$ (69)	$ —	$ 47
Liabilities						
Commodity derivatives	$ (3)	$ (213)	$ —	$ 69	$ 6	$ (141)
Interest-rate derivatives	—	(1,376)	—	—	117	(1,259)
Total derivative liabilities	$ (3)	$ (1,589)	$ —	$ 69	$ 123	$ (1,400)
December 31, 2015						
Assets						
Commodity derivatives	$ 10	$ 460	$ —	$ (178)	$ (8)	$ 284
Interest-rate derivatives	—	56	—	—	—	56
Total derivative assets	$ 10	$ 516	$ —	$ (178)	$ (8)	$ 340
Liabilities						
Commodity derivatives	$ (1)	$ (179)	$ —	$ 178	$ —	$ (2)
Interest-rate derivatives	—	(1,542)	—	—	58	(1,484)
Total derivative liabilities	$ (1)	$ (1,721)	$ —	$ 178	$ 58	$ (1,486)

(1) Represents the impact of netting commodity derivative assets and liabilities with counterparties where the Company has the contractual right and intends to net settle.

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10. Tangible Equity Units

In June 2015, the Company issued 9.2 million 7.50% TEUs at a stated amount of $50.00 per TEU and raised net proceeds of $445 million. Each TEU is comprised of a prepaid equity purchase contract for common units of WGP and a senior amortizing note. Subsequent to issuance, each TEU may be legally separated into the two components. The prepaid equity purchase contract is considered a freestanding financial instrument, indexed to WGP common units, and meets the conditions for equity classification.

Anadarko allocated the proceeds from the issuance of the TEUs to equity and debt based on the relative fair values of their respective components as follows:

millions, except price per TEU	Equity Component	Debt Component	Total
Price per TEU	$ 39.05	$ 10.95	$ 50.00
Gross proceeds	359	101	460
Less issuance costs	11	4	15
Net proceeds	$ 348	$ 97	$ 445

The prepaid equity purchase contracts were recorded in noncontrolling interests, net of issuance costs, and the senior amortizing notes were recorded in short-term debt and long-term debt on the Company's Consolidated Balance Sheet.

Equity Component Unless settled earlier at the holder's option, each purchase contract has a mandatory settlement date of June 7, 2018. Anadarko has a right to elect to issue and deliver shares of Anadarko Petroleum Corporation common stock (APC Shares) in lieu of delivering WGP common units at settlement. The Company will deliver WGP common units (or APC Shares) on the settlement date at the settlement rate based upon the applicable market value of WGP common units (or APC Shares) as follows:

	Settlement Rate per Purchase Contract [1]	
Applicable Market Value of WGP Common Units [1]	**WGP Common Units**	**APC Shares (if elected)**
Exceeds $69.1181 (Threshold Appreciation Price)	0.7234 units (Minimum Settlement Rate)	a number of shares equal to (a) the Minimum Settlement Rate, multiplied by the applicable market value of WGP common units, divided by (b) 98% of the applicable market value of APC Shares
Less than or equal to the Threshold Appreciation Price, but greater than or equal to $57.5901 (Reference Price)	a number of units equal to $50.00, divided by the applicable market value of WGP common units	a number of shares equal to $50.00, divided by 98% of the applicable market value of APC Shares
Less than the Reference Price	0.8682 units (Maximum Settlement Rate)	a number of shares equal to (a) the Maximum Settlement Rate, multiplied by the applicable market value of WGP common units, divided by (b) 98% of the applicable market value of APC Shares

(1) The applicable market value is the average of the daily volume-weighted average prices of WGP common units (or APC Shares) for the 20 consecutive trading days beginning on, and including, the 23rd scheduled trading day immediately preceding June 7, 2018.

ANADARKO PETROLEUM CORPORATION
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10. Tangible Equity Units (Continued)

The WGP common units underlying the purchase contract are currently issued and outstanding, and are owned by a wholly owned subsidiary of Anadarko. In the event Anadarko elects to settle in APC Shares, the number of such shares issued and delivered upon settlement of each purchase contract is subject to adjustment and cannot exceed the APC Share cap of 4.0629 shares under any circumstance. The above fixed settlement rates for WGP common units and the APC Share cap are subject to adjustment upon the occurrence of certain specified dilutive events such as certain increases in the WGP distribution rate or the payment of dividends by Anadarko.

Debt Component Each senior amortizing note has an initial principal amount of $10.95 and bears interest at 1.50% per year. Beginning September 7, 2015, Anadarko began paying equal quarterly cash installments of $0.9375 per amortizing note (except for the September 7, 2015 installment payment, which was $0.9063 per amortizing note). The payments constitute a payment of interest and partial repayment of principal, with the aggregate per-year payments of principal and interest equating to a 7.50% cash payment with respect to each TEU. The senior amortizing notes have a final installment payment date of June 7, 2018, and are senior unsecured obligations of the Company. For activity related to the senior amortizing notes, see *Note 11—Debt and Interest Expense*.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
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11. Debt and Interest Expense

Debt Activity The following summarizes the Company's borrowing activity, after eliminating the effect of intercompany transactions:

	Carrying Value				
millions	WES	WGP [1]	Anadarko [2]	Anadarko Consolidated	Description
Balance at December 31, 2014	$ 2,409	$ —	$ 12,574	$ 14,983	
Issuances	490	—	—	490	WES 3.950% Senior Notes due 2025
	—	—	97	97	TEUs - senior amortizing notes
Borrowings	—	—	1,500	1,500	$5.0 Billion Facility
	—	—	1,800	1,800	364-Day Facility
	400	—	—	400	WES RCF
	—	—	250	250	Commercial paper notes, net [3]
Repayments	—	—	(1,500)	(1,500)	$5.0 Billion Facility
	—	—	(1,800)	(1,800)	364-Day Facility
	(610)	—	—	(610)	WES RCF
	—	—	(16)	(16)	TEUs - senior amortizing notes
Other, net	2	—	52	54	Amortization of discounts, premiums, and debt issuance costs
Balance at December 31, 2015	$ 2,691	$ —	$ 12,957	$ 15,648	
Issuances	—	—	**794**	**794**	4.850% Senior Notes due 2021 [4]
	—	—	**1,088**	**1,088**	5.550% Senior Notes due 2026 [4]
	—	—	**1,088**	**1,088**	6.600% Senior Notes due 2046 [4]
	495	—	—	**495**	WES 4.650% Senior Notes due 2026
	203	—	—	**203**	WES 5.450% Senior Notes due 2044
Borrowings	—	—	**1,750**	**1,750**	364-Day Facility
	600	—	—	**600**	WES RCF
	—	**28**	—	**28**	WGP RCF
Repayments	—	—	**(1,749)**	**(1,749)**	5.950% Senior Notes due 2016
	—	—	**(1,994)**	**(1,994)**	6.375% Senior Notes due 2017
	—	—	**(1,750)**	**(1,750)**	364-Day Facility
	(900)	—	—	**(900)**	WES RCF
	—	—	**(250)**	**(250)**	Commercial paper notes, net
	—	—	**(34)**	**(34)**	TEUs - senior amortizing notes
Other, net	**2**	—	**59**	**61**	Amortization of discounts, premiums, and debt issuance costs
Balance at December 31, 2016	**$ 3,091**	**$ 28**	**$ 11,959**	**$ 15,078**	

(1) Excludes WES.
(2) Excludes WES and WGP.
(3) Includes repayments of $(106) million related to commercial paper notes with maturities greater than 90 days.
(4) Represent senior notes issued in March 2016.

During the second quarter of 2016, the Company used proceeds from its $3.0 billion March 2016 Senior Notes issuances to purchase and retire $1.250 billion of its $2.0 billion 6.375% Senior Notes due September 2017 pursuant to a tender offer and to redeem its $1.750 billion 5.950% Senior Notes due September 2016. In December 2016, the Company redeemed its remaining $750 million 6.375% Senior Notes due September 2017. The Company recognized losses of $155 million for the early retirement and redemption of these senior notes, which included $144 million of premiums paid.

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11. Debt and Interest Expense (Continued)

Debt See *Note 8—Equity-Method Investments* for disclosure regarding Anadarko's notes payable related to its ownership of certain noncontrolling mandatorily redeemable interests that are not included in the Company's reported debt balance and do not affect consolidated interest expense. The following summarizes the Company's outstanding debt, including capital lease obligations, after eliminating the effect of intercompany transactions:

	December 31, 2016			
millions	WES	WGP [1]	Anadarko [2]	Anadarko Consolidated
7.050% Debentures due 2018	$ —	$ —	$ 114	$ 114
TEUs - senior amortizing notes due 2018	—	—	51	51
WES 2.600% Senior Notes due 2018	350	—	—	350
6.950% Senior Notes due 2019	—	—	300	300
8.700% Senior Notes due 2019	—	—	600	600
4.850% Senior Notes due 2021	—	—	800	800
WES 5.375% Senior Notes due 2021	500	—	—	500
WES 4.000% Senior Notes due 2022	670	—	—	670
3.450% Senior Notes due 2024	—	—	625	625
6.950% Senior Notes due 2024	—	—	650	650
WES 3.950% Senior Notes due 2025	500	—	—	500
WES 4.650% Senior Notes due 2026	500	—	—	500
5.550% Senior Notes due 2026	—	—	1,100	1,100
7.500% Debentures due 2026	—	—	112	112
7.000% Debentures due 2027	—	—	54	54
7.125% Debentures due 2027	—	—	150	150
6.625% Debentures due 2028	—	—	17	17
7.150% Debentures due 2028	—	—	235	235
7.200% Debentures due 2029	—	—	135	135
7.950% Debentures due 2029	—	—	117	117
7.500% Senior Notes due 2031	—	—	900	900
7.875% Senior Notes due 2031	—	—	500	500
Zero-Coupon Senior Notes due 2036	—	—	2,360	2,360
6.450% Senior Notes due 2036	—	—	1,750	1,750
7.950% Senior Notes due 2039	—	—	325	325
6.200% Senior Notes due 2040	—	—	750	750
4.500% Senior Notes due 2044	—	—	625	625
WES 5.450% Senior Notes due 2044	600	—	—	600
6.600% Senior Notes due 2046	—	—	1,100	1,100
7.730% Debentures due 2096	—	—	61	61
7.500% Debentures due 2096	—	—	78	78
7.250% Debentures due 2096	—	—	49	49
WGP RCF	—	28	—	28
Total borrowings at face value	$ 3,120	$ 28	$ 13,558	$ 16,706
Net unamortized discounts, premiums, and debt issuance costs [3]	(29)	—	(1,599)	(1,628)
Total borrowings [4]	3,091	28	11,959	15,078
Capital lease obligations	—	—	245	245
Less short-term debt	—	—	42	42
Total long-term debt	$ 3,091	$ 28	$ 12,162	$ 15,281

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11. Debt and Interest Expense (Continued)

	December 31, 2015			
millions	WES	WGP [1]	Anadarko [2]	Anadarko Consolidated
Commercial paper	$ —	$ —	$ 250	$ 250
5.950% Senior Notes due 2016	—	—	1,750	1,750
6.375% Senior Notes due 2017	—	—	2,000	2,000
7.050% Debentures due 2018	—	—	114	114
TEUs - senior amortizing notes due 2018	—	—	85	85
WES 2.600% Senior Notes due 2018	350	—	—	350
6.950% Senior Notes due 2019	—	—	300	300
8.700% Senior Notes due 2019	—	—	600	600
WES 5.375% Senior Notes due 2021	500	—	—	500
WES 4.000% Senior Notes due 2022	670	—	—	670
3.450% Senior Notes due 2024	—	—	625	625
6.950% Senior Notes due 2024	—	—	650	650
WES 3.950% Senior Notes due 2025	500	—	—	500
7.500% Debentures due 2026	—	—	112	112
7.000% Debentures due 2027	—	—	54	54
7.125% Debentures due 2027	—	—	150	150
6.625% Debentures due 2028	—	—	17	17
7.150% Debentures due 2028	—	—	235	235
7.200% Debentures due 2029	—	—	135	135
7.950% Debentures due 2029	—	—	117	117
7.500% Senior Notes due 2031	—	—	900	900
7.875% Senior Notes due 2031	—	—	500	500
Zero-Coupon Senior Notes due 2036	—	—	2,360	2,360
6.450% Senior Notes due 2036	—	—	1,750	1,750
7.950% Senior Notes due 2039	—	—	325	325
6.200% Senior Notes due 2040	—	—	750	750
4.500% Senior Notes due 2044	—	—	625	625
WES 5.450% Senior Notes due 2044	400	—	—	400
7.730% Debentures due 2096	—	—	61	61
7.500% Debentures due 2096	—	—	78	78
7.250% Debentures due 2096	—	—	49	49
WES RCF	300	—	—	300
Total borrowings at face value	$ 2,720	$ —	$ 14,592	$ 17,312
Net unamortized discounts, premiums, and debt issuance costs [3]	(29)	—	(1,635)	(1,664)
Total borrowings [4]	2,691	—	12,957	15,648
Capital lease obligations	—	—	20	20
Less short-term debt	—	—	32	32
Total long-term debt	$ 2,691	$ —	$ 12,945	$ 15,636

(1) Excludes WES.
(2) Excludes WES and WGP.
(3) Unamortized discounts, premiums, and debt issuance costs are amortized over the term of the related debt. Debt issuance costs related to revolving credit facilities are included in other current assets and other assets on the Company's Consolidated Balance Sheets.
(4) The Company's outstanding borrowings, except for borrowings under the WGP RCF, are senior unsecured.

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11. Debt and Interest Expense (Continued)

In a 2006 private offering, Anadarko received $500 million of loan proceeds upon issuing the Zero Coupons. The Zero Coupons mature in 2036 and have an aggregate principal amount due at maturity of approximately $2.4 billion, reflecting a yield to maturity of 5.24%. The Zero Coupons can be put to the Company in October of each year, in whole or in part, for the then-accreted value of the outstanding Zero Coupons. The accreted value of the outstanding Zero Coupons was $849 million at December 31, 2016. Anadarko's Zero Coupons were classified as long-term debt on the Company's Consolidated Balance Sheet at December 31, 2016, as the Company has the ability and intent to refinance these obligations using long-term debt, should the put be exercised.

Scheduled Maturities Total principal amount of debt maturities related to borrowings for the five years ending December 31, 2021, excluding the potential repayment of the outstanding Zero Coupons that may be put by the holders to the Company annually, were as follows:

	Principal Amount of Debt Maturities			
millions	WES	WGP [1]	Anadarko [2]	Anadarko Consolidated
2017	$ —	$ —	$ 34	$ 34
2018	350	—	131	481
2019	—	28	900	928
2020	—	—	—	—
2021	500	—	800	1,300

(1) Excludes WES.
(2) Excludes WES and WGP.

Fair Value The Company uses a market approach to determine the fair value of its fixed-rate debt using observable market data, which results in a Level 2 fair-value measurement. The carrying amount of floating-rate debt approximates fair value as the interest rates are variable and reflective of market rates. The estimated fair value of the Company's total borrowings was $17.1 billion at December 31, 2016, and $15.7 billion at December 31, 2015.

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11. Debt and Interest Expense (Continued)

Anadarko Revolving Credit Facilities and Commercial Paper Program Anadarko has a $3.0 billion five-year senior unsecured revolving credit facility maturing in January 2021 (Five-Year Facility). In addition, the Company has a $2.0 billion 364-day senior unsecured revolving credit facility (364-Day Facility). In January 2017, the Company extended the maturity date of the 364-Day Facility until 2018.

Borrowings under the Five-Year Facility and the 364-Day Facility (collectively, the Credit Facilities) generally bear interest under one of two rate options, at Anadarko's election, using either LIBOR (or Euro Interbank Offered Rate in the case of borrowings under the Five-Year Facility denominated in Euro) or an alternate base rate, in each case plus an applicable margin ranging from 0.00% to 1.65% for the Five-Year Facility and 0.00% to 1.675% for the 364-Day Facility. The applicable margin will vary depending on Anadarko's credit ratings.

The Credit Facilities contain certain customary affirmative and negative covenants, including a financial covenant requiring maintenance of a consolidated indebtedness to total capitalization ratio of no greater than 65% (excluding the effect of non-cash write-downs), and limitations on certain secured indebtedness, sale-and-leaseback transactions, and mergers and other fundamental changes. At December 31, 2016, the Company had no outstanding borrowings under the Credit Facilities and was in compliance with all related covenants.

In January 2015, the Company initiated a commercial paper program, which allows for a maximum of $3.0 billion of unsecured commercial paper notes and is supported by the Five-Year Facility. The maturities of the commercial paper notes may vary, but may not exceed 397 days. In February 2016, Moody's downgraded the Company's commercial paper program credit rating, which eliminated the Company's access to the commercial paper market. The Company has not issued commercial paper notes since the downgrade and had no outstanding borrowings under the commercial paper program at December 31, 2016.

WES and WGP Borrowings In July 2016, WES completed a public offering of $500 million aggregate principal amount of 4.650% Senior Notes due July 2026. Net proceeds were used to repay a portion of the amount outstanding under WES's $1.2 billion five-year senior unsecured revolving credit facility previously maturing in February 2019 (WES RCF), which is expandable to $1.5 billion. In October 2016, WES completed a public offering of $200 million aggregate principal amount of 5.450% Senior Notes due April 2044. Net proceeds were primarily used to repay amounts outstanding under the WES RCF, and the remaining proceeds were used for general partnership purposes, including capital expenditures. In December 2016, WES amended the WES RCF to extend the maturity date to February 2020.

Borrowings under the WES RCF bear interest at LIBOR plus an applicable margin ranging from 0.975% to 1.45% depending on WES's credit rating, or the greatest of (i) rates at a margin above the one-month LIBOR, (ii) the federal funds rate, or (iii) prime rates offered by certain designated banks. At December 31, 2016, WES had no outstanding borrowings under its RCF, had outstanding letters of credit of $5 million, and had available borrowing capacity of $1.195 billion. At December 31, 2016, WES was in compliance with all related covenants.

In March 2016, WGP entered into a $250 million three-year senior secured revolving credit facility maturing in March 2019 (WGP RCF), which is expandable to $500 million, subject to receiving increased or new commitments from lenders and the satisfaction of certain other conditions. Obligations under the WGP RCF are secured by a first priority lien on all of WGP's assets (not including the consolidated assets of WES), as well as all equity interests owned by WGP. Borrowings under the WGP RCF bear interest at LIBOR (with a floor of 0%), plus applicable margins ranging from 2.00% to 2.75% depending on WGP's consolidated leverage ratio, or at a base rate equal to the greatest of (i) the prime rate, (ii) the federal funds rate plus 0.50%, or (iii) LIBOR plus 1.00%, in each case plus applicable margins ranging from 1.00% to 1.75% based upon WGP's consolidated leverage ratio. At December 31, 2016, WGP had outstanding borrowings under its RCF of $28 million at an interest rate of 2.77%, had available borrowing capacity of $222 million, and was in compliance with all related covenants.

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11. Debt and Interest Expense (Continued)

Capital Lease Obligations Construction of a FPSO for the Company's TEN field in Ghana commenced in 2013. The Company recognized an asset and related obligation for its approximate 19% nonoperated working interest share during the construction period. Upon completion of the construction in the third quarter of 2016, the Company reported the asset and related obligation as a capital lease of $225 million for the Company's proportionate share of the fair value of the FPSO. The FPSO lease provides for an initial term of 10 years with annual renewal periods for an additional 10 years, annual purchase options that decrease over time, and no residual value guarantees. The capital lease asset will be depreciated over the estimated proved reserves of the TEN field using the UOP method, with the associated depreciation included in DD&A in the Company's Consolidated Statement of Income. The capital lease obligation will be accreted to the present value of the minimum lease payments using the effective interest method. The Company expects to make the first payment related to the FPSO in the first quarter of 2017.

At December 31, 2016, future minimum lease payments related to the Company's capital leases were:

millions		
2017	$	57
2018		42
2019		42
2020		43
2021		42
Remaining years		391
Total future minimum lease payments	$	617
Less portion representing imputed interest		372
Capital lease obligations	$	245

Interest Expense The following summarizes interest expense for the years ended December 31:

millions		**2016**		2015		2014
Debt and other	**$**	**1,022**	$	989	$	973
Capitalized interest		**(132)**		(164)		(201)
Total interest expense	**$**	**890**	$	825	$	772

ANADARKO PETROLEUM CORPORATION
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12. Income Taxes

The following summarizes components of income tax expense (benefit) for the years ended December 31:

millions	**2016**	2015	2014
Current			
Federal	**$ (140)**	$ (177)	$ 188
State	**(1)**	(18)	2
Foreign	**378**	495	1,574
	237	300	1,764
Deferred			
Federal	**(1,020)**	(2,929)	(389)
State	**(148)**	(145)	27
Foreign	**(90)**	(103)	215
	(1,258)	(3,177)	(147)
Total income tax expense (benefit)	**$ (1,021)**	$ (2,877)	$ 1,617

Total income taxes differed from the amounts computed by applying the U.S. federal statutory income tax rate to income (loss) before income taxes. The following summarizes the sources of these differences for the years ended December 31:

millions except percentages	**2016**	2015	2014
Income (loss) before income taxes			
Domestic	**$ (3,728)**	$ (9,155)	$ (3,564)
Foreign	**(101)**	(534)	3,618
Total	**$ (3,829)**	$ (9,689)	$ 54
U.S. federal statutory tax rate	**35%**	35%	35%
Tax computed at the U.S. federal statutory rate	**$ (1,340)**	$ (3,391)	$ 19
Adjustments resulting from			
State income taxes (net of federal income tax benefit)	**(108)**	(81)	(11)
Tax impact from foreign operations	**80**	299	62
Non-deductible Algerian exceptional profits tax	**106**	102	193
Net changes in uncertain tax positions	**90**	54	1,427
(Income) loss attributable to noncontrolling interests	**(92)**	42	(66)
Dispositions of non-deductible goodwill	**205**	62	21
Other, net	**38**	36	(28)
Total income tax expense (benefit)	**$ (1,021)**	$ (2,877)	$ 1,617
Effective tax rate	**27%**	30%	2,994%

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
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12. Income Taxes (Continued)

The following summarizes components of total deferred taxes at December 31:

millions	**2016**	2015
Federal	**$ (3,805)**	$ (4,721)
State, net of federal	**(173)**	(248)
Foreign	**(332)**	(431)
Total deferred taxes	**$ (4,310)**	$ (5,400)

The following summarizes tax effects of temporary differences that give rise to significant portions of the deferred tax assets (liabilities) at December 31:

millions	**2016**	2015
Deferred tax liabilities		
Oil and gas exploration and development operations	**$ (5,054)**	$ (5,643)
Midstream and other depreciable properties	**(870)**	(1,049)
Mineral operations	**(550)**	(492)
Other	**(147)**	(470)
Gross long-term deferred tax liabilities	**(6,621)**	(7,654)
Deferred tax assets		
Foreign and state net operating loss carryforwards	**648**	586
U.S. foreign tax credit carryforwards	**1,834**	1,254
Compensation and benefit plans	**672**	615
Mark to market on derivatives	**324**	441
Other	**588**	761
Gross long-term deferred tax assets	**4,066**	3,657
Valuation allowances on deferred tax assets not expected to be realized	**(1,755)**	(1,403)
Net long-term deferred tax assets	**2,311**	2,254
Total deferred taxes	**$ (4,310)**	$ (5,400)

The valuation allowance primarily relates to U.S. foreign tax credit carryforwards and foreign and state net operating loss carryforwards, which reduces the Company's net deferred tax asset to an amount that will more likely than not be realized within the carryforward period.

The following summarizes changes in the balance of valuation allowances on deferred tax assets:

millions	**2016**	2015	2014
Balance at January 1	**$ (1,403)**	$ (864)	$ (818)
Changes due to U.S. foreign tax credits	**(477)**	(384)	11
Changes due to foreign and state net operating loss carryforwards	**13**	10	64
Changes due to foreign capitalized costs	**112**	(165)	(121)
Balance at December 31	**$ (1,755)**	$ (1,403)	$ (864)

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
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12. Income Taxes (Continued)

Tax carryforwards available for use on future income tax returns, prior to valuation allowance, at December 31, 2016, were as follows:

millions	Domestic	Foreign	Expiration
Net operating loss—foreign	$ —	$ 1,498	2017 - Indefinite
Net operating loss—state	$ 4,888	$ —	2017-2036
Foreign tax credits	$ 1,834	$ —	2023-2027
Texas margins tax credit	$ 34	$ —	2026

The following summarizes taxes receivable (payable) related to income tax expense (benefit) at December 31:

millions **Balance Sheet Classification**	**2016**	2015
Income taxes receivable		
Accounts receivable—other	**$ 180**	$ 1,046
Other assets	**67**	61
	247	1,107
Income taxes (payable)		
Accrued expense	**(6)**	(9)
Total net income taxes receivable (payable)	**$ 241**	$ 1,098

Changes in the balance of unrecognized tax benefits excluding interest and penalties on uncertain tax positions were as follows:

	Assets (Liabilities)		
millions	**2016**	2015	2014
Balance at January 1	**$ (1,780)**	$ (1,687)	$ (147)
Increases related to prior-year tax positions	**(86)**	(99)	(11)
Decreases related to prior-year tax positions	**436**	89	39
Increases related to current-year tax positions	**(26)**	(263)	(1,568)
Settlements	**—**	180	—
Balance at December 31	**$ (1,456)**	$ (1,780)	$ (1,687)

Included in the 2016 ending balance of unrecognized tax benefits presented above are potential benefits of $1.424 billion, of which, if recognized, $1.397 billion would affect the effective tax rate on income. Also included in the 2016 ending balance are benefits of $33 million related to tax positions for which the ultimate deductibility is highly certain, but the timing of such deductibility is uncertain.

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12. Income Taxes (Continued)

As of December 31, 2016, the Company had recorded a total tax benefit of $576 million related to the Tronox-related contingent liability. This benefit is net of a $1.3 billion uncertain tax position due to the uncertainty related to the deductibility of the settlement payment. It is reasonably possible that the amount of the uncertain tax position related to the settlement could change, perhaps materially. See *Note 16—Contingencies—Tronox Litigation*.

Income tax audits and the Company's acquisition and divestiture activity have given rise to tax disputes in U.S. and foreign jurisdictions. See *Note 16—Contingencies—Other Litigation.* Over the next 12 months, it is reasonably possible that the total amount of unrecognized tax benefits could decrease by $50 million to $100 million due to settlements with taxing authorities or lapse in statutes of limitation. With the exception of the deductibility of the Tronox settlement payment discussed above, management does not believe that the final resolution of outstanding tax audits and litigation will have a material adverse effect on the Company's consolidated financial condition, results of operations, or cash flows.

The Company had accrued approximately $31 million of interest related to uncertain tax positions at December 31, 2016, and $11 million at December 31, 2015. The Company recognized interest and penalties in income tax expense (benefit) of $21 million during 2016 and $2 million during 2015.

Anadarko is subject to audit by tax authorities in the U.S. federal, state, and local tax jurisdictions as well as in various foreign jurisdictions. The following lists the tax years subject to examination by major tax jurisdiction:

	Tax Years
United States	2012-2015
Algeria	2012-2015
Ghana	2006-2015

13. Asset Retirement Obligations

The majority of Anadarko's AROs relate to the plugging of wells and the related abandonment of oil and gas properties. Revisions in estimated liabilities during the period relate primarily to changes in estimates of asset retirement costs and include, but are not limited to, revisions of estimated inflation rates, changes in property lives, and the expected timing of settlement. The following summarizes changes in the Company's AROs:

millions	**2016**	2015
Carrying amount at January 1	**$ 2,059**	$ 2,053
Liabilities acquired [(1)]	**813**	—
Liabilities incurred	**93**	104
Property dispositions	**(88)**	(108)
Liabilities settled	**(225)**	(298)
Accretion expense	**100**	102
Revisions in estimated liabilities	**179**	206
Carrying amount at December 31	**$ 2,931**	$ 2,059

(1) In December 2016, the Company closed the GOM Acquisition. See *Note 3—Acquisitions, Divestitures, and Assets Held for Sale* for additional information.

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14. Conveyance of Future Hard Minerals Royalty Revenues

During the first quarter of 2016, the Company conveyed a limited-term nonparticipating royalty interest in certain of its coal and trona leases to a third party for $413 million, net of transaction costs. Such conveyance entitles the third party to receive up to $553 million in future royalty revenue over a period of not less than 10 years and not greater than 15 years. Additionally, such third party is entitled to receive 3% of the aggregate royalties earned during the first 10 years between $800 million and $900 million and 4% of the aggregate royalties earned during the first 10 years that exceed $900 million. Generally, such third party relies solely on the royalty payments to recover its investment and, as such, has the risk of the royalties not being sufficient to recover its investment over the term of the conveyance.

Proceeds from this transaction were accounted for as deferred revenues and are included in accrued expenses and other long-term liabilities on the Company's Consolidated Balance Sheet. The deferred revenues will be amortized to other revenues, included in gains (losses) on divestitures and other, net on a unit-of-revenue basis over the term of the agreement. Net proceeds received from the third party were reported in financing activities on the Company's Consolidated Statement of Cash Flows. Semi-annual payments to the third party are scheduled on March 1 and September 1 of each year through March 1, 2026. The specified future amounts that the Company expects to pay and the payment timing are subject to change based upon the actual royalties received by the Company during the term of the conveyance. Royalties received by Anadarko under this agreement are reported in operating activities on the Company's Consolidated Statement of Cash Flows. The semi-annual payments to the third party, up to the aggregate amount of the $413 million net proceeds the Company received for the conveyance in the first quarter of 2016, are reported in financing activities on the Company's Consolidated Statement of Cash Flows. Any additional payments to the third party are reported in operating activities on the Company's Consolidated Statement of Cash Flows to offset the royalties received.

During the year ended December 31, 2016, the Company amortized $37 million of deferred revenues as a result of this agreement. The Company made the first semi-annual payment of $25 million for royalties in 2016. The following summarizes the remaining amounts that the Company expects to pay, prior to the potential 3% to 4% of any excess described above:

millions	
2017	$ 50
2018	50
2019	52
2020	56
2021	57
Later years	263
Total	$ 528

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15. Commitments

Operating Leases At December 31, 2016, the Company had $1.2 billion in long-term drilling rig commitments that are accounted for as operating leases. The Company also had $320 million of various commitments under non-cancelable operating lease agreements for production platforms and equipment, buildings, facilities, compressors, aircraft, and vessels. These operating leases expire at various dates through 2026. Certain of these operating leases contain residual value guarantees at the end of the lease term of $82 million at December 31, 2016. No liability was accrued for residual value guarantees. In addition, these operating leases include options to purchase the leased property during or at the end of the lease term for the fair market value or other specified amount at that time. The following summarizes future minimum lease payments under operating leases at December 31, 2016:

millions	
2017	$ 673
2018	480
2019	234
2020	81
2021	29
Later years	23
Total future minimum lease payments	$ 1,520

Anadarko has entered into various agreements to secure drilling rigs necessary to support the execution of its drilling plans over the next several years. The table of future minimum lease payments above includes $1.15 billion related to five offshore drilling vessels and $50 million related to certain contracts for U.S. onshore drilling rigs. Lease payments associated with the drilling of exploratory wells and development wells net of amounts billed to partners will initially be capitalized as a component of oil and gas properties, and either depreciated or impaired in future periods or written off as exploration expense.

Total rent expense, net of sublease income and amounts capitalized, amounted to $73 million in 2016, $77 million in 2015, and $85 million in 2014. Total rent expense included contingent rent expense related to transportation and processing fees of $6 million in 2016, $17 million in 2015, and $22 million in 2014.

Other Commitments Anadarko has various long-term contractual commitments pertaining to oil and natural-gas activities such as work-related commitments for drilling wells, obtaining and processing seismic data, and fulfilling rig commitments. Anadarko also enters into various processing, transportation, storage, and purchase agreements to access markets and provide flexibility to sell its oil, natural gas, and NGLs in certain areas. These agreements expire at various dates through 2033. The following summarizes the gross aggregate future payments under these contracts at December 31, 2016:

millions	
2017	$ 1,328
2018	1,207
2019	1,001
2020	934
2021	677
Later years	1,224
Total future minimum lease payments [(1)]	$ 6,371

(1) Excludes purchase commitments for jointly owned fields and facilities for which the Company is not the operator.

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16. Contingencies

Litigation The Company is a defendant in a number of lawsuits, is involved in governmental proceedings, and is subject to regulatory controls arising in the ordinary course of business, including personal injury claims; property damage claims; title disputes; tax disputes; royalty claims; contract claims; contamination claims relating to oil and gas exploration, production, transportation, and processing; and environmental claims, including claims involving assets owned by acquired companies and claims involving assets previously sold to third parties and no longer a part of the Company's current operations. The Company's Consolidated Balance Sheets include liabilities of $7 million at December 31, 2016, and $269 million at December 31, 2015, for litigation-related contingencies. Anadarko is also subject to various environmental-remediation and reclamation obligations arising from federal, state, and local laws and regulations. While the ultimate outcome and impact on the Company cannot be predicted with certainty, after consideration of recorded expense and liability accruals, management believes that the resolution of pending proceedings will not have a material adverse effect on the Company's consolidated financial condition, results of operations, or cash flows.

Deepwater Horizon Events In April 2010, the Macondo well in the Gulf of Mexico blew out and an explosion occurred on the *Deepwater Horizon* drilling rig, resulting in an oil spill. The well was operated by BP Exploration and Production Inc. (BP) and Anadarko held a 25% nonoperated interest. In October 2011, the Company and BP entered into a settlement agreement, mutual releases, and agreement to indemnify relating to the Deepwater Horizon events (Settlement Agreement) under which the Company paid $4.0 billion in cash and transferred its interest in the Macondo well and the Mississippi Canyon Block 252 to BP. Pursuant to the Settlement Agreement, the Company is fully indemnified by BP against all claims, causes of action, losses, costs, expenses, liabilities, damages or judgments of any kind arising out of the Deepwater Horizon events, related damage claims arising under the Oil Pollution Act of 1990 (OPA), claims for natural resource damages (NRD) and assessment costs, and any claims arising under the Operating Agreement with BP. This indemnification is guaranteed by BP Corporation North America Inc. (BPCNA) and, in the event that the net worth of BPCNA declines below an agreed upon amount, BP p.l.c. has agreed to become the sole guarantor. Under the Settlement Agreement, BP does not indemnify the Company against penalties and fines, punitive damages, shareholder derivative or securities laws claims, or certain other claims.

Numerous Deepwater Horizon event-related civil lawsuits were filed against BP and other parties, including the Company. Generally, the plaintiffs sought actual damages, punitive damages, declaratory judgment, and/or injunctive relief. This litigation was consolidated into a federal Multidistrict Litigation (MDL) action pending before Judge Carl Barbier in the U.S. District Court for the Eastern District of Louisiana in New Orleans, Louisiana (Louisiana District Court).

BP Consent Decree In July 2015, BP announced a settlement agreement in principle with the U.S. Department of Justice (DOJ) and certain states and local government entities regarding essentially all of the outstanding claims against BP related to the Deepwater Horizon event (BP Settlement) and, in October 2015, lodged a proposed consent decree with the Louisiana District Court. In April 2016, the Louisiana District Court approved the consent decree. As a result of the BP Settlement and approval of the consent decree, all liability relating to OPA-related environmental costs was resolved and all NRD claims and claims by the United States and the Gulf states impacted by the event relating to the MDL action were dismissed. For any remaining claims relating to the MDL action, the Company is fully indemnified by BP against any losses pursuant to the Settlement Agreement.

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16. Contingencies (Continued)

Penalties and Fines In December 2010, the DOJ on behalf of the United States, filed a civil lawsuit in the Louisiana District Court against several parties, including the Company, seeking an assessment of civil penalties under the Clean Water Act (CWA) in an amount to be determined by the Louisiana District Court. After previously finding that Anadarko, as a nonoperating investor in the Macondo well, was not culpable with respect to the Deepwater Horizon events, the Louisiana District Court found Anadarko liable for civil penalties under Section 311 of the CWA as a working-interest owner in the Macondo well and entered a judgment of $159.5 million in December 2015. Neither party appealed the decision and the Company paid the penalty in the first quarter of 2016.

Tronox Litigation In August 2006, Anadarko acquired all of the stock of Kerr-McGee Corporation. In January 2009, Tronox, a former subsidiary of Kerr-McGee Corporation which completed an IPO in November 2005 (Tronox), and certain of Tronox's subsidiaries filed voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code. In May 2009, Tronox and certain of its affiliates filed a lawsuit against Anadarko and Kerr-McGee Corporation and certain of its subsidiaries (collectively, Kerr-McGee) asserting several claims, including claims for actual and constructive fraudulent conveyance (Adversary Proceeding). Tronox alleged, among other things, that it was insolvent or undercapitalized at the date of its IPO and sought, among other things, to recover damages in excess of $18.85 billion from Kerr-McGee and Anadarko as well as interest and attorneys' fees and costs.

The U.S. government intervened in the Adversary Proceeding, and in May 2009 asserted separate claims against Anadarko and Kerr-McGee under the Federal Debt Collection Procedures Act (FDCPA Complaint). Pursuant to Tronox's Plan of Reorganization, a litigation trust (Litigation Trust) pursued the Adversary Proceeding against the Company.

On April 3, 2014, Anadarko and Kerr-McGee entered into a settlement agreement with the Litigation Trust and the U.S. government (on behalf of itself and certain U.S. government agencies) to resolve all claims asserted in the Adversary Proceeding and FDCPA Complaint for $5.15 billion, which represents principal of approximately $3.98 billion plus 6% interest from the filing of the Adversary Proceeding on May 12, 2009, through April 3, 2014. In addition, the Company agreed to pay interest on the above amount from April 3, 2014, through the payment of the settlement. In January 2015, the Company paid $5.2 billion after the settlement agreement became effective.

Anadarko recognized Tronox-related contingent losses of $850 million in the fourth quarter of 2013 and $4.3 billion in the first quarter of 2014. In addition, Anadarko recognized settlement-related interest expense, included in Tronox-related contingent loss in the Company's Consolidated Statements of Income, of $60 million during 2014 and $5 million during the first quarter of 2015. At December 31, 2016 and 2015, there was no Tronox-related contingent liability on the Company's Consolidated Balance Sheet. For information on the tax effects of the Tronox settlement agreement, see *Note 12—Income Taxes*.

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16. Contingencies (Continued)

Other Litigation In December 2008, Anadarko sold its interest in the Peregrino heavy-oil field offshore Brazil. The Company is currently litigating a dispute with the Brazilian tax authorities regarding the tax rate applicable to the transaction. In December 2008, the Company deposited the amount of tax originally in dispute in a Brazilian real-denominated judicially-controlled Brazilian bank account pending final resolution of the matter. At December 31, 2016, the deposit of $104 million is included in other assets on the Company's Consolidated Balance Sheet.

In July 2009, the lower judicial court ruled in favor of the Brazilian tax authorities. The Company appealed this decision to the Brazilian Regional courts, which upheld the lower court's ruling in favor of the Brazilian tax authorities in December 2011. In April 2012, the Company filed simultaneous appeals to the Brazilian Superior Court and the Brazilian Supreme Court. The appeal to the Brazilian Supreme Court has been stayed pending a decision in the Superior Court appeal.

In August 2013, following a determination by an administrative court in a related matter that the amount of tax in dispute was not calculated properly, the Company filed a petition requesting the withdrawal of a portion of the judicial deposit to the extent it exceeds the amount of tax currently in dispute and any interest on such excess amount. In April 2015, the Company's petition was denied. The Company appealed this decision. The appeal was denied in November 2015.

The Company believes that it will more likely than not prevail in the Brazilian Superior Court and the Brazilian Supreme Court. Therefore, no tax liability has been recorded for Peregrino divestiture-related litigation at December 31, 2016. The Company continues to vigorously defend its position in Brazilian courts.

Guarantees and Indemnifications The Company provides certain indemnifications in relation to asset dispositions. These indemnifications typically relate to disputes, litigation, or tax matters existing at the date of disposition. In 2013, as a result of a Chapter 11 bankruptcy declaration by a third party, the Department of the Interior ordered Anadarko to perform the decommissioning of a production facility and related wells, which were previously sold to the third party. At December 31, 2015, the Company had a decommissioning obligation recorded of $116 million. Anadarko completed the decommissioning obligations, and at December 31, 2016, the Company had no remaining liability recorded.

Environmental Matters Anadarko is also subject to various environmental-remediation and reclamation obligations arising from federal, state, and local laws and regulations. The Company's Consolidated Balance Sheets include liabilities for remediation and reclamation obligations of $118 million at December 31, 2016, and $145 million at December 31, 2015. The current portion of these amounts was included in accounts payable and the long-term portion of these amounts was included in other long-term liabilities—other on the Company's Consolidated Balance Sheets. The Company continually monitors remediation and reclamation processes and adjusts its liability for these obligations as necessary.

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17. Restructuring Charges

In the first quarter of 2016, the Company initiated a workforce reduction program to align the size and composition of its workforce with its expected future operating and capital plans. Employee notifications related to the workforce reduction program were completed by June 30, 2016. All restructuring charges were recognized in 2016, with the exception of an estimated $42 million of settlement expense for retirement benefits to be recognized in 2017. The 2017 settlement expense is expected to be triggered by lump-sum payments to terminated participants and the amount could vary depending on market conditions and participant elections. The following summarizes the total expected restructuring charges and the amounts expensed during the year ended December 31, 2016, which are included in general and administrative expenses in the Company's Consolidated Statements of Income:

millions	Total Expected Costs	Year Ended December 31, 2016
Costs by category		
Cash severance	$ 153	$ 153
Retirement benefits [1]	239	197
Share-based compensation	39	39
Total	$ 431	$ 389

[1] Includes termination benefits, curtailments, and settlements. See *Note 18—Pension Plans and Other Postretirement Benefits*.

The following summarizes the changes in the cash severance-related liability included in accounts payable on the Company's Consolidated Balance Sheet:

millions	2016
Balance at January 1	$ —
Accruals	153
Payments	(145)
Balance at December 31	$ 8

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18. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans

The Company has contributory and non-contributory defined-benefit pension plans, which include both qualified and supplemental plans. The Company also provides certain health care and life insurance benefits for certain retired employees. Retiree health care benefits are funded by contributions from the retiree and, in certain circumstances, contributions from the Company. The Company's retiree life insurance plan is non-contributory.

The following sets forth changes in the benefit obligations and fair value of plan assets for the Company's pension and other postretirement benefit plans for the years ended December 31, 2016 and 2015, as well as the funded status of the plans and amounts recognized in the financial statements at December 31, 2016 and 2015:

	Pension Benefits		Other Benefits	
millions	**2016**	2015	**2016**	2015
Change in benefit obligation				
Benefit obligation at beginning of year	**$ 2,431**	$ 2,528	**$ 266**	$ 373
Service cost	**99**	118	**3**	9
Interest cost	**95**	101	**12**	15
Plan amendments	**—**	—	**—**	(89)
Actuarial (gain) loss [(1)]	**211**	(115)	**34**	(27)
Participant contributions	**—**	—	**4**	5
Benefit payments	**(513)**	(194)	**(23)**	(20)
Foreign-currency exchange-rate changes	**(22)**	(7)	**—**	—
Benefit obligation at end of year [(2)]	**$ 2,301**	$ 2,431	**$ 296**	$ 266
Change in plan assets				
Fair value of plan assets at beginning of year	**$ 1,674**	$ 1,818	**$ —**	$ —
Actual return on plan assets	**107**	16	**—**	—
Employer contributions	**101**	43	**19**	15
Participant contributions	**—**	—	**4**	5
Benefit payments	**(513)**	(194)	**(23)**	(20)
Foreign-currency exchange-rate changes	**(29)**	(9)	**—**	—
Fair value of plan assets at end of year	**$ 1,340**	$ 1,674	**$ —**	$ —
Funded status of the plans at end of year	**$ (961)**	$ (757)	**$ (296)**	$ (266)
Total recognized amounts in the balance sheet consist of				
Other assets	**$ 44**	$ 41	**$ —**	$ —
Accrued expenses	**(66)**	(24)	**(23)**	(16)
Other long-term liabilities—other	**(939)**	(774)	**(273)**	(250)
Total	**$ (961)**	$ (757)	**$ (296)**	$ (266)
Total recognized amounts in accumulated other comprehensive income consist of				
Prior service cost (credit)	**$ —**	$ (1)	**$ (50)**	$ (84)
Net actuarial (gain) loss	**616**	655	**—**	(25)
Total	**$ 616**	$ 654	**$ (50)**	$ (109)

(1) Includes $44 million of termination benefits, $2 million related to curtailment for pension, and $9 million related to curtailment for other benefits at December 31, 2016, associated with the Company's workforce reduction program initiated in the first quarter of 2016. See *Note 17—Restructuring Charges*.

(2) The accumulated benefit obligation for all defined-benefit pension plans was $2.0 billion at December 31, 2016 and $2.1 billion at December 31, 2015.

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18. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

The following summarizes the Company's defined-benefit pension plans with accumulated benefit obligations in excess of plan assets for the years ended December 31:

millions	**2016**	2015
Projected benefit obligation	**$ 2,175**	$ 2,309
Accumulated benefit obligation	**1,866**	1,954
Fair value of plan assets	**1,171**	1,511

The following summarizes the Company's pension and other postretirement benefit cost for the years ended December 31:

	Pension Benefits			**Other Benefits**		
millions	**2016**	2015	2014	**2016**	2015	2014
Components of net periodic benefit cost						
Service cost	**$ 99**	$ 118	$ 99	**$ 3**	$ 9	$ 7
Interest cost	**95**	101	99	**12**	15	15
Expected (return) loss on plan assets	**(97)**	(109)	(106)	**—**	—	—
Amortization of net actuarial loss (gain)	**42**	52	34	**—**	—	(7)
Amortization of net prior service cost (credit)	**—**	—	—	**(25)**	(4)	—
Settlement expense [(1)]	**146**	11	—	**—**	—	—
Termination benefits expense [(1)]	**44**	—	—	**—**	—	—
Curtailment expense [(1)]	**8**	—	—	**—**	—	—
Net periodic benefit cost	**$ 337**	$ 173	$ 126	**$ (10)**	$ 20	$ 15

(1) During 2016, settlement expenses, termination benefits expense, and curtailment expense primarily relate to the workforce reduction program initiated in the first quarter of 2016. See *Note 17—Restructuring Charges*.

The following summarizes the amounts recognized in other comprehensive income (before tax benefit) for the years ended December 31:

	Pension Benefits			**Other Benefits**		
millions	**2016**	2015	2014	**2016**	2015	2014
Amounts recognized in other comprehensive income (expense)						
Net actuarial gain (loss)	**$ (150)**	$ 22	$ (333)	**$ (25)**	$ 27	$ (72)
Amortization of net actuarial (gain) loss	**188**	63	34	**—**	—	(7)
Net prior service (cost) credit	**—**	—	—	**—**	89	—
Amortization of net prior service cost (credit)	**—**	—	—	**(34)**	(4)	—
Total amounts recognized in other comprehensive income (expense)	**$ 38**	$ 85	$ (299)	**$ (59)**	$ 112	$ (79)

The Company amortizes prior service costs (credits) on a straight-line basis over the average remaining service period of employees expected to receive benefits under each plan. Actuarial gains and losses that exceed 10% of the greater of the projected benefit obligation and the market-related value of assets are amortized over the average remaining service period of participating employees expected to receive benefits under each plan. In 2017, an estimated $20 million of net actuarial loss and $24 million of net prior service credit for the pension and other postretirement plans will be amortized from accumulated other comprehensive income into net periodic benefit cost.

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18. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

Defined-benefit plan obligations and costs are actuarially determined, incorporating the use of various assumptions. Critical assumptions for pension and other postretirement plans include the discount rate, the expected long-term rate of return on plan assets (for funded pension plans), the rate of future compensation increases, and inflation (for postretirement plans). Other assumptions involve demographic factors such as retirement age, mortality, and turnover. The Company evaluates and updates its actuarial assumptions at least annually.

Accumulated and projected benefit obligations are measured as the present value of future cash payments. The Company discounts those cash payments using a discount rate that reflects the weighted average of market-observed yields for select high-quality (AA-rated) fixed-income securities with cash flows that correspond to the expected amounts and timing of benefit payments. The discount-rate assumption used by the Company represents an estimate of the interest rate at which the pension and other postretirement benefit obligations could effectively be settled on the measurement date. Assumed rates of compensation increases for active participants vary by age group, with the resulting weighted-average assumed rate (weighted by the plan-level benefit obligation) provided in the preceding table.

The following summarizes the weighted-average assumptions used by the Company in determining the pension and other postretirement benefit obligations and net periodic benefit cost for the years ended December 31:

	Pension Benefits			Other Benefits		
	2016	2015	2014	**2016**	2015	2014
Benefit obligation assumptions						
Discount rate	**4.06%**	4.50%	4.00%	**4.26%**	5.00%	4.25%
Rates of increase in compensation levels	**5.40%**	5.25%	5.25%	**5.48%**	5.50%	5.25%
Net periodic benefit cost assumptions						
Discount rate	**4.62%**	4.00%	4.75%	**5.00%**	4.25%	5.25%
Long-term rate of return on plan assets	**6.77%**	6.75%	6.75%	**N/A**	N/A	N/A
Rates of increase in compensation levels	**5.34%**	5.25%	5.00%	**5.41%**	5.25%	5.25%

An annual rate of increase indexed to the Consumer Price Index is assumed for purposes of measuring other postretirement benefit obligations. A rate of 2.00% at December 31, 2016, and 1.75% at December 31, 2015, was assumed for purposes of measuring other postretirement benefit obligations.

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18. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

Plan Assets

Investment Policies and Strategies The Company has adopted a balanced, diversified investment strategy, with the intent of maximizing returns without exposure to undue risk. Investments are typically made through investment managers across several investment categories (domestic equity securities, international equity securities, fixed-income securities, real estate, hedge funds, and private equity), with selective exposure to Growth/Value investment styles. Performance for each investment is measured relative to the appropriate index benchmark for its category. Target asset-allocation percentages by major category are 45%-55% equity securities, 20%-30% fixed income, and up to 25% in a combination of other investments such as real estate, hedge funds, and private equity. Investment managers have full discretion as to investment decisions regarding funds under their management to the extent permitted within investment guidelines.

Although investment managers may, at their discretion and within investment guidelines, invest in Anadarko securities, there are no direct investments in Anadarko securities included in plan assets. There may be, however, indirect investments in Anadarko securities through the plans' collective fund investments. The expected long-term rate of return on plan assets assumption was determined using the year-end 2016 pension investment balances by asset class and expected long-term asset allocation. The expected return for each asset class reflects capital-market projections formulated using a forward-looking building-block approach while also taking into account historical return trends and current market conditions. Equity returns generally reflect long-term expectations of real earnings growth, dividend yield, and inflation. Returns on fixed-income securities are generally developed based on expected inflation, real bond yield, and risk spread (as appropriate), adjusted for the expected effect that changing yields have on the rate of return. Other asset-class returns are derived from their relationship to the equity and fixed-income markets.

Risks and Uncertainties The plan assets include various investment securities that are exposed to various risks such as interest-rate, credit, and market risks. Due to the level of risk associated with certain investment securities, it is possible that changes in the values of investment securities could significantly impact the plan assets.

The plan assets may include securities with contractual cash flows such as asset-backed securities, collateralized mortgage obligations, and commercial mortgage-backed securities, including securities backed by subprime mortgage loans. The value, liquidity, and related income of those securities are sensitive to changes in economic conditions, including real estate values, delinquencies or defaults, or both, and may be adversely affected by shifts in the market's perception of the issuers and changes in interest rates.

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18. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

Investments in securities traded in active markets are measured based on unadjusted quoted prices, which represent Level 1 inputs. Investments based on Level 2 inputs include direct investments in corporate debt and other fixed-income securities. Investments included as Level 3 inputs are not observable from objective sources.

The fair value of the Company's pension plan assets by asset class and input level within the fair-value hierarchy were as follows:

millions				
December 31, 2016	**Level 1**	**Level 2**	**Level 3** [(3)]	**Total**
Investments				
Cash and cash equivalents	**$ 2**	**$ —**	**$ —**	**$ 2**
Fixed income				
Mortgage-backed securities	**—**	**1**	**—**	**1**
Other fixed-income securities	**59**	**32**	**—**	**91**
Equity securities				
Domestic	**248**	**—**	**—**	**248**
International	**99**	**—**	**—**	**99**
Other				
Real estate	**—**	**—**	**10**	**10**
Other	**—**	**28**	**—**	**28**
Investments measured at net asset value [(1)]	**—**	**—**	**—**	**861**
Total investments [(2)]	**$ 408**	**$ 61**	**$ 10**	**$ 1,340**
December 31, 2015				
Investments				
Cash and cash equivalents	$ 5	$ —	$ —	$ 5
Fixed income				
Mortgage-backed securities	—	1	—	1
U.S. government securities	—	1	—	1
Other fixed-income securities	46	32	—	78
Equity securities				
Domestic	330	—	—	330
International	130	—	—	130
Other				
Real estate	—	—	13	13
Hedge funds	7	—	—	7
Other	—	30	—	30
Investments measured at net asset value [(1)]	—	—	—	1,081
Total investments [(2)]	$ 518	$ 64	$ 13	$ 1,676
Liabilities				
Hedge funds	$ (3)	$ —	$ —	$ (3)
Total liabilities	$ (3)	$ —	$ —	$ (3)

(1) Certain investments measured at fair value using the net asset value per share (or its equivalent) have not been categorized in the fair value hierarchy. Amounts presented in this table are intended to reconcile the fair value hierarchy to the pension plan assets.

(2) Amount excludes receivables and payables, primarily related to Level 1 investments.

(3) The changes in level 3 investments of $(3) million for the year ended December 31, 2016, and $1 million for the year ended December 31, 2015, were attributable to the actual return on plan assets still held at the reporting date.

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18. Pension Plans, Other Postretirement Benefits, and Defined-Contribution Plans (Continued)

Cash Contributions and Expected Benefit Payments While reported benefit obligations exceed the fair value of pension and other postretirement plan assets at December 31, 2016, the Company monitors the status of its funded pension plans to ensure that plan funds are sufficient to continue paying benefits. Contributions to funded plans increase plan assets, while contributions to unfunded plans are used to fund current benefit payments.

The following summarizes the Company's contributions for 2016 and expected contributions for 2017:

millions	Expected 2017	2016
Funded pension plans	$ 140	$ 3
Unfunded pension plans	67	98
Unfunded other postretirement plans	24	19
Total	$ 231	$ 120

The following summarizes estimated benefit payments for the next 10 years, including benefit increases due to continuing employee service:

millions	Pension Benefit Payments	Other Benefit Payments
2017	$ 302	$ 24
2018	147	20
2019	166	20
2020	164	20
2021	171	19
2022-2026	1,009	93

Defined-Contribution Plans The Company maintains several defined-contribution benefit plans, the most significant of which is the Anadarko Employee Savings Plan (ESP). All regular employees of the Company on its U.S. payroll are eligible to participate in the ESP by making elective contributions that are matched by the Company, subject to certain limitations. The Company recognized expense related to these plans of $64 million for 2016, and $76 million for both 2015 and 2014.

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19. Stockholders' Equity

Common Stock In September 2016, the Company completed a public offering of 40.5 million shares of its common stock at a price of $53.23 per share. Net proceeds of $2.16 billion from this equity issuance were primarily used to fund the GOM Acquisition. The remaining net proceeds were used for general corporate purposes. See *Note 3—Acquisitions, Divestitures, and Assets Held for Sale*. The following summarizes the changes in the Company's outstanding shares of common stock:

millions	**2016**	2015	2014
Shares of common stock issued			
Shares at January 1	**528**	526	523
Exercise of stock options	**1**	1	2
Issuance of common stock	**41**	—	—
Issuance of restricted stock	**2**	1	1
Shares at December 31	**572**	528	526
Shares of common stock held in treasury			
Shares at January 1	**20**	19	19
Shares received for restricted stock vested and stock options exercised	**1**	1	—
Shares at December 31	**21**	20	19
Shares of common stock outstanding at December 31	**551**	508	507

Earnings Per Share The Company's basic earnings per share (EPS) is computed based on the average number of shares of common stock outstanding for the period and includes the effect of any participating securities and TEUs as appropriate. Diluted EPS includes the effect of the Company's outstanding stock options, restricted stock awards, restricted stock units, TEUs, and WES Series A Preferred units, if the inclusion of these items is dilutive.

The following provides a reconciliation between basic and diluted EPS attributable to common stockholders for the years ended December 31:

millions except per-share amounts	**2016**	2015	2014
Net income (loss)			
Net income (loss) attributable to common stockholders	**$ (3,071)**	$ (6,692)	$ (1,750)
Income (loss) effect of TEUs	**(6)**	—	—
Less distributions on participating securities	**1**	3	4
Basic	**$ (3,078)**	$ (6,695)	$ (1,754)
Income (loss) effect of TEUs	**(1)**	—	—
Diluted	**$ (3,079)**	$ (6,695)	$ (1,754)
Shares			
Average number of common shares outstanding—basic	**522**	508	506
Average number of common shares outstanding—diluted	**522**	508	506
Excluded due to anti-dilutive effect	**11**	11	11
Net income (loss) per common share			
Basic	**$ (5.90)**	$ (13.18)	$ (3.47)
Diluted	**$ (5.90)**	$ (13.18)	$ (3.47)

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20. Accumulated Other Comprehensive Income (Loss)

The following summarizes the after-tax changes in the balances of accumulated other comprehensive income (loss):

millions	Interest-rate Derivatives Previously Subject to Hedge Accounting	Pension and Other Postretirement Plans	Total
Balance at December 31, 2013	$ (54)	$ (231)	$ (285)
Other comprehensive income (loss), before reclassifications	—	(256)	(256)
Reclassifications to Consolidated Statement of Income	6	18	24
Net other comprehensive income (loss)	6	(238)	(232)
Balance at December 31, 2014	$ (48)	$ (469)	$ (517)
Other comprehensive income (loss), before reclassifications	—	87	87
Reclassifications to Consolidated Statement of Income	6	41	47
Net other comprehensive income (loss)	6	128	134
Balance at December 31, 2015	$ (42)	$ (341)	$ (383)
Other comprehensive income (loss), before reclassifications	**—**	**(107)**	**(107)**
Reclassifications to Consolidated Statement of Income	**5**	**94**	**99**
Net other comprehensive income (loss)	**5**	**(13)**	**(8)**
Balance at December 31, 2016	**$ (37)**	**$ (354)**	**$ (391)**

21. Share-Based Compensation

At December 31, 2016, 34 million shares of the 42 million shares of Anadarko common stock authorized for awards under active share-based compensation plans remained available for future issuance. The Company generally issues new shares to satisfy awards under employee share-based payment plans. The number of shares available is reduced by awards granted. The following summarizes share-based compensation expense for the years ended December 31:

millions	**2016**	2015	2014
Restricted stock [(1)]	**$ 175**	$ 157	$ 144
Stock options [(1)]	**20**	19	21
Other equity-classified awards	**2**	1	1
Value creation plan	**—**	(4)	136
Performance-based unit awards [(1)]	**38**	(1)	23
Pretax share-based compensation expense	**$ 235**	$ 172	$ 325
Income tax benefit	**$ 86**	$ 64	$ 120

(1) Includes restructuring charges of $31 million for restricted stock, $1 million for stock options, and $7 million for performance-based unit awards in 2016. See *Note 17—Restructuring Charges* for further discussion.

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21. Share-Based Compensation (Continued)

Cash flows from financing activities included excess tax benefits related to share-based compensation of zero in 2016, $6 million in 2015, and $22 million in 2014. Cash received from stock option exercises was $30 million in 2016, $28 million in 2015, and $99 million in 2014.

Equity-Classified Awards

Restricted Stock Certain employees may be granted restricted stock in the form of restricted stock awards or restricted stock units. Restricted stock is subject to forfeiture restrictions and cannot be sold, transferred, or disposed of during the restriction period. The holders of restricted stock awards have the same rights as a stockholder of the Company with respect to such shares, including the right to vote and receive dividends or other distributions paid with respect to the shares. A restricted stock unit is equivalent to a restricted stock award except that unit holders do not have the right to vote. Restricted stock vests over service periods ranging from the date of grant generally up to three years and is not considered issued and outstanding for accounting purposes until vested.

Non-employee directors are granted deferred shares, which are also considered restricted stock, that are held in a grantor trust by the Company until payable. Non-employee directors may receive these shares in a lump-sum payment or in annual installments.

The following summarizes the Company's restricted stock activity:

	Shares *(millions)*		**Weighted-Average Grant-Date Fair Value** *(per share)*
Non-vested at January 1, 2016	3.98	$	82.39
Granted	3.11	$	52.03
Vested	(2.43)	$	81.19
Forfeited	(0.12)	$	63.78
Non-vested at December 31, 2016	4.54	$	62.74

The weighted-average grant-date fair value per share of restricted stock granted was $79.40 during 2015 and $87.42 during 2014. The total fair value of restricted shares vested was $114 million during 2016, $141 million during 2015, and $132 million during 2014, based on the market price at the vesting date. At December 31, 2016, total unrecognized compensation cost related to restricted stock of $188 million is expected to be recognized over a weighted-average remaining service period of 2.0 years.

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21. Share-Based Compensation (Continued)

Stock Options Certain employees may be granted nonqualified options to purchase shares of Anadarko common stock with an exercise price equal to, or greater than, the fair market value of Anadarko common stock on the date of grant. These stock options generally vest over three years from the date of grant and terminate at the earlier of the date of exercise or seven years from the date of grant.

The fair value of stock option awards is determined using the Black-Scholes option-pricing model with the following assumptions:

- *Expected life*—Based on historical exercise behavior.
- *Volatility*—Based on an average of historical volatility over the expected life of an option and the 12-month average implied volatility.
- *Risk-free interest rates*—Based on the U.S. Treasury rate over the expected life of an option.
- *Dividend yield*—Based on a 12-month average dividend yield, taking into account the Company's expected dividend policy over the expected life of an option.
- *Expected forfeiture*—Based on historical forfeiture experience.

The Company used the following weighted-average assumptions to estimate the fair value of stock options granted:

	2016	2015	2014
Weighted-average grant-date fair value	**$ 15.92**	$ 18.18	$ 23.55
Assumptions			
Expected option life—years	**4.1**	4.9	4.9
Volatility	**38.2%**	32.4%	29.9%
Risk-free interest rate	**1.3%**	1.4%	1.6%
Dividend yield	**0.6%**	1.4%	1.1%

The following summarizes the Company's stock option activity:

	Shares *(millions)*	**Weighted-Average Exercise Price** *(per share)*	**Weighted-Average Remaining Contractual Term** *(years)*	**Aggregate Intrinsic Value** *(millions)*
Outstanding at January 1, 2016	7.05	$ 71.86		
Granted	1.38	$ 67.74		
Exercised [(1)]	(0.90)	$ 33.69		
Forfeited or expired	(0.91)	$ 72.40		
Outstanding at December 31, 2016	6.62	$ 76.10	3.18	$ 10.6
Vested or expected to vest at December 31, 2016	6.56	$ 76.15	3.16	$ 10.4
Exercisable at December 31, 2016	5.05	$ 78.61	2.22	$ 3.5

(1) The total intrinsic value of stock options exercised was $7 million during 2016, $23 million during 2015, and $88 million during 2014, based on the difference between the market price at the exercise date and the exercise price.

At December 31, 2016, total unrecognized compensation cost related to stock options of $28 million is expected to be recognized over a weighted-average remaining service period of 2.0 years.

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21. Share-Based Compensation (Continued)

Liability-Classified Awards

Value Creation Plan As a part of its employee compensation program, the Company offered an incentive compensation program that provided non-officer employees the opportunity to earn cash bonus awards based on the Company's TSR for the year, compared to the TSR of a predetermined group of peer companies. The Company paid $134 million during 2015 related to the plan and zero during 2014. The Value Creation Plan was discontinued as an active plan beginning in 2015.

Performance-Based Unit Awards Certain officers of the Company were provided Performance Unit Award Agreements with two- and three-year performance periods. The vesting of these units is based on comparing the Company's TSR to the TSR of each of a predetermined group of peer companies over the specified performance period. Each performance unit represents the value of one share of the Company's common stock. Following the end of each performance period, the value of the vested performance units, if any, is paid in cash. The Company paid $6 million related to vested performance units in 2016, $9 million in 2015, and $12 million in 2014. At December 31, 2016, the Company's liability under Performance Unit Award Agreements was $49 million, with total unrecognized compensation cost related to these awards of $47 million expected to be recognized over a weighted-average remaining performance period of 2.1 years.

22. Noncontrolling Interests

WES is a limited partnership formed by Anadarko to acquire, own, develop, and operate midstream assets. During the first quarter of 2016, WES issued 14 million Series A Preferred units to private investors for net proceeds of $440 million, and issued 1.3 million common units to the Company. Proceeds from these issuances were used to acquire interests in Springfield Pipeline LLC from the Company. During the second quarter of 2016, WES issued an additional eight million Series A Preferred units to private investors, pursuant to the full exercise of an option granted in connection with the initial issuance, and raised net proceeds of $247 million.

WES issued approximately 874 thousand common units to the public and raised net proceeds of $57 million in 2015, and issued approximately 10 million common units to the public and raised net proceeds of $691 million in 2014. In addition, WES issued 11 million Class C units to Anadarko in 2014 to partially fund the DBM acquisition. These units will receive quarterly distributions in the form of additional Class C units until the end of 2017, unless WES elects to convert the units to common units earlier or Anadarko elects to extend the conversion date. WES distributed 946 thousand Class C units to Anadarko during 2016 and 498 thousand Class C units during 2015.

WGP is a limited partnership formed by Anadarko to own interests in WES. Anadarko sold 12.5 million WGP common units to the public for net proceeds of $476 million in 2016, 2.3 million WGP common units to the public for net proceeds of $130 million in 2015, and approximately 6 million WGP common units to the public for net proceeds of $335 million in 2014. In June 2015, Anadarko issued 9.2 million TEUs, which include an equity component that may be settled in WGP common units. For additional disclosure of the TEU effect on noncontrolling interests, see *Note 10—Tangible Equity Units*. At December 31, 2016, Anadarko's ownership interest in WGP consisted of an 81.6% limited partner interest and the entire non-economic general partner interest. The remaining 18.4% limited partner interest in WGP was owned by the public.

At December 31, 2016, WGP's ownership interest in WES consisted of a 29.9% limited partner interest, the entire 1.5% general partner interest, and all of the WES incentive distribution rights. At December 31, 2016, Anadarko also owned an 8.6% limited partner interest in WES through other subsidiaries' ownership of common and Class C units. The remaining 60.0% limited partner interest in WES was owned by the public.

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23. Variable Interest Entities

Consolidated VIEs The Company determined that the partners in WGP and WES with equity at risk lack the power, through voting rights or similar rights, to direct the activities that most significantly impact WGP's and WES's economic performance; therefore, WGP and WES are considered VIEs. Anadarko, through its ownership of the general partner interest in WGP, has the power to direct the activities that most significantly affect economic performance and the obligation to absorb losses or the right to receive benefits that could be potentially significant to WGP and WES; therefore, Anadarko is considered the primary beneficiary and consolidates WGP and WES. See *Note 22—Noncontrolling Interests* for additional information on WGP and WES.

Assets and Liabilities of VIEs The assets of WGP and WES cannot be used by Anadarko for general corporate purposes and are both included in and disclosed parenthetically on the Company's Consolidated Balance Sheets. The carrying amounts of liabilities related to WGP and WES for which the creditors do not have recourse to other assets of the Company are both included in and disclosed parenthetically on the Company's Consolidated Balance Sheets.

All outstanding debt for WES at December 31, 2016 and 2015, including any borrowings under the WES RCF, is recourse to WES's general partner, which in turn has been indemnified in certain circumstances by certain wholly owned subsidiaries of the Company for such liabilities. All outstanding debt for WGP at December 31, 2016 and 2015, including any borrowings under the WGP RCF, is recourse to WGP's general partner, which is a wholly owned subsidiary of the Company. See *Note 11—Debt and Interest Expense* for additional information on WGP and WES long-term debt balances.

VIE Financing WGP's sources of liquidity include borrowings under its RCF and distributions from WES. WES's sources of liquidity include cash and cash equivalents, cash flows generated from operations, interest income from a note receivable from Anadarko as discussed below, borrowings under its RCF, the issuance of additional partnership units, or debt offerings. See *Note 11—Debt and Interest Expense* and *Note 22—Noncontrolling Interests* for additional information on WGP and WES financing activity.

Financial Support Provided to VIEs Concurrent with the closing of its May 2008 IPO, WES loaned the Company $260 million in exchange for a 30-year note bearing interest at a fixed annual rate of 6.50%, payable quarterly. The related interest income for WES was $17 million for each of the years ended December 31, 2016 and 2015. The note receivable and related interest income are eliminated in consolidation.

In March 2015, WES acquired the Company's interest in DBJV. The acquisition was financed using a deferred purchase price obligation which requires a cash payment from WES to the Company due on March 31, 2020. The cash payment due to the Company is equal to eight multiplied by the average of WES's share in DBJV Net Earnings for 2018 and 2019 less WES's share of capital expenditures incurred for DBJV from March 1, 2015 to February 29, 2020. Net Earnings is defined as all revenues less cost of product, operating expenses, and property taxes. The net present value of this obligation was $41 million at December 31, 2016, and $189 million at December 31, 2015. The reduction in the value of the deferred purchase price obligation was primarily due to revisions reflecting an increase in WES's estimate of capital expenditures to be incurred by DBJV, partially offset by an increase in WES's estimate of future Net Earnings.

Anadarko has commodity price swap agreements in place with WES expiring on December 31, 2017. WES has recorded a capital contribution from Anadarko in its Consolidated Statement of Equity and Partners' Capital for the amount by which the swap price exceeds the applicable market price. WES recorded a $46 million capital contribution from Anadarko for the year ended December 31, 2016, and a capital contribution of $18 million for the year ended December 31, 2015.

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24. Supplemental Cash Flow Information

Additions to properties and equipment as presented within Anadarko's cash flows from investing activities include cash payments for cost of properties, equipment, and facilities. The cost of properties includes the initial capitalization of drilling costs associated with all exploratory wells whether or not they were deemed to have a commercially sufficient quantity of proved reserves. For the year ended December 31, 2015, the Company's Consolidated Statement of Cash Flows included an $881 million increase in tax receivable related to the Tronox settlement included in (increase) decrease in accounts receivable, offset by an $881 million uncertain tax position included in other items, net.

The following summarizes cash paid (received) for interest and income taxes, as well as non-cash investing and financing activities, for the years ended December 31:

millions	**2016**	2015	2014
Cash paid (received)			
Interest, net of amounts capitalized [1]	**$ 856**	$ 2,019	$ 689
Income taxes, net of refunds [2]	**(882)**	26	956
Non-cash investing activities			
Fair value of properties and equipment from non-cash transactions	**$ 3**	$ 178	$ 18
Asset retirement cost additions	**298**	273	348
Accruals of property, plant, and equipment	**549**	754	1,177
Net liabilities assumed (divested) in acquisitions and divestitures	**723**	(114)	(92)
Property insurance receivable	**—**	49	—
Acquisition receivable	**(32)**	—	—
Non-cash investing and financing activities			
Acquisition contingent consideration	**$ 103**	$ —	$ —
Capital lease obligation [3]	**10**	—	13
FPSO construction period obligation [3]	**11**	59	128
Deferred drilling lease liability	**30**	—	—

(1) Includes $1.2 billion of interest related to the Tronox settlement payment in 2015.

(2) Includes $881 million from a tax refund related to the income tax benefit associated with the Company's 2015 tax net operating loss carryback.

(3) Upon completion of the FPSO in the third quarter of 2016, the Company reported the construction period obligation as a capital lease obligation based on the fair-value of the FPSO. See *Note 11—Debt and Interest Expense*.

25. Segment Information

Anadarko's business segments are separately managed due to distinct operational differences and unique technology, distribution, and marketing requirements. The Company's three reporting segments are oil and gas exploration and production, midstream, and marketing. The oil and gas exploration and production segment explores for and produces oil, natural gas, and NGLs, and plans for the development and operation of the Company's LNG project in Mozambique. The midstream segment engages in gathering, processing, treating, and transporting Anadarko and third-party oil, natural-gas, and NGLs production. The midstream reporting segment consists of two operating segments, WES and other midstream, which are aggregated into one reporting segment due to similar financial and operating characteristics. The marketing segment sells much of Anadarko's oil, natural-gas, and NGLs production, as well as third-party purchased volumes.

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25. Segment Information (Continued)

To assess the performance of Anadarko's operating segments, the chief operating decision maker analyzes Adjusted EBITDAX. The Company defines Adjusted EBITDAX as income (loss) before income taxes; gains (losses) on divestitures, net; exploration expense; DD&A; impairments; interest expense; total (gains) losses on derivatives, net, less net cash from settlement of commodity derivatives; and certain items not related to the Company's normal operations, less net income (loss) attributable to noncontrolling interests. During the periods presented, items not related to the Company's normal operations included restructuring charges related to the workforce reduction program included in general and administrative expenses, Deepwater Horizon settlement and related costs included in other operating expenses, loss on early extinguishment of debt, Tronox-related contingent loss, and certain other nonoperating items included in other (income) expense, net. The Company's definition of Adjusted EBITDAX excludes gains (losses) on divestitures, net and exploration expense as they are not indicators of operating efficiency for a given reporting period. However, exploration expense is monitored by management as part of costs incurred in exploration and development activities. Similarly, DD&A and impairments are excluded from Adjusted EBITDAX as a measure of segment operating performance because capital expenditures are evaluated at the time capital costs are incurred. Adjusted EBITDAX also excludes interest expense to allow for assessment of segment operating results without regard to Anadarko's financing methods or capital structure. Total (gains) losses on derivatives, net, less net cash from settlement of commodity derivatives are excluded from Adjusted EBITDAX because these (gains) losses are not considered a measure of asset operating performance. Finally, net income (loss) attributable to noncontrolling interests is excluded from the Company's measure of Adjusted EBITDAX because it represents earnings that are not attributable to the Company's common stockholders.

Management believes Adjusted EBITDAX provides information useful in assessing the Company's operating and financial performance across periods. Adjusted EBITDAX as defined by Anadarko may not be comparable to similarly titled measures used by other companies and should be considered in conjunction with net income (loss) attributable to common stockholders and other performance measures, such as operating income. Below is a reconciliation of consolidated Adjusted EBITDAX to income (loss) before income taxes for the years ended December 31:

millions	**2016**	2015	2014
Income (loss) before income taxes	**$ (3,829)**	$ (9,689)	$ 54
(Gains) losses on divestitures, net	**757**	1,022	(1,891)
Exploration expense	**946**	2,644	1,639
DD&A	**4,301**	4,603	4,550
Impairments	**227**	5,075	836
Interest expense	**890**	825	772
Total (gains) losses on derivatives, net, less net cash from settlement of commodity derivatives	**559**	235	578
Restructuring charges	**389**	—	—
Other operating expense	**1**	74	97
Loss on early extinguishment of debt	**155**	—	—
Tronox-related contingent loss	**—**	5	4,360
Certain other nonoperating items	**(58)**	22	22
Less net income (loss) attributable to noncontrolling interests	**263**	(120)	187
Consolidated Adjusted EBITDAX	**$ 4,075**	$ 4,936	$ 10,830

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25. Segment Information (Continued)

The Company's accounting policies for individual segments are the same as those described in the summary of significant accounting policies, with the following exception: certain intersegment commodity contracts may meet the GAAP definition of a derivative instrument, which would be accounted for at fair value under GAAP. However, Anadarko does not recognize any mark-to-market adjustments on such intersegment arrangements. Additionally, intersegment asset transfers are accounted for at historical cost basis, and do not give rise to gain or loss recognition.

Information presented below as "Other and Intersegment Eliminations" includes corporate costs, results from hard-minerals royalties, and net cash from settlement of commodity derivatives. The following summarizes selected financial information for Anadarko's reporting segments:

millions	Oil and Gas Exploration & Production	Midstream	Marketing	Other and Intersegment Eliminations	Total
2016					
Sales revenues	$ 4,191	$ 635	$ 3,621	$ —	$ 8,447
Intersegment revenues	2,651	1,403	(3,094)	(960)	—
Other	—	—	—	179	179
Total revenues and other [(1)]	6,842	2,038	527	(781)	8,626
Operating costs and expenses [(2)]	3,238	978	691	(303)	4,604
Net cash from settlement of commodity derivatives	—	—	—	(265)	(265)
Other (income) expense, net [(3)]	—	—	—	(43)	(43)
Net income (loss) attributable to noncontrolling interests	—	263	—	—	263
Total expenses and other	3,238	1,241	691	(611)	4,559
Total (gains) losses on derivatives, net included in marketing revenue, less net cash from settlement	—	—	8	—	8
Adjusted EBITDAX	$ 3,604	$ 797	$ (156)	$ (170)	$ 4,075
Net properties and equipment	$ 24,251	$ 5,913	$ —	$ 2,004	$ 32,168
Capital expenditures	$ 2,685	$ 550	$ —	$ 79	$ 3,314
Goodwill	$ 4,550	$ 450	$ —	$ —	$ 5,000

(1) Total revenues and other excludes gains (losses) on divestitures, net since these gains and losses are excluded from Adjusted EBITDAX.
(2) Operating costs and expenses excludes exploration expense, DD&A, impairments, restructuring charges, and other operating expense since these expenses are excluded from Adjusted EBITDAX.
(3) Other (income) expense, net excludes certain other nonoperating items since these items are excluded from Adjusted EBITDAX.

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25. Segment Information (Continued)

millions	Oil and Gas Exploration & Production	Midstream	Marketing	Other and Intersegment Eliminations	Total
2015					
Sales revenues	$ 4,734	$ 727	$ 4,025	$ —	$ 9,486
Intersegment revenues	3,178	1,207	(3,476)	(909)	—
Other	—	—	—	234	234
Total revenues and other [(1)]	7,912	1,934	549	(675)	9,720
Operating costs and expenses [(2)]	3,456	998	743	(86)	5,111
Net cash from settlement of commodity derivatives	—	—	—	(335)	(335)
Other (income) expense, net [(3)]	—	—	—	127	127
Net income (loss) attributable to noncontrolling interests	—	(120)	—	—	(120)
Total expenses and other	3,456	878	743	(294)	4,783
Total (gains) losses on derivatives, net included in marketing revenue, less net cash from settlement	—	—	(1)	—	(1)
Adjusted EBITDAX	$ 4,456	$ 1,056	$ (195)	$ (381)	$ 4,936
Net properties and equipment	$ 25,742	$ 5,876	$ —	$ 2,133	$ 33,751
Capital expenditures	$ 5,029	$ 770	$ —	$ 89	$ 5,888
Goodwill	$ 4,945	$ 450	$ —	$ —	$ 5,395
2014					
Sales revenues	$ 8,603	$ 484	$ 7,288	$ —	$ 16,375
Intersegment revenues	6,225	1,338	(6,771)	(792)	—
Other	—	—	—	204	204
Total revenues and other [(1)]	14,828	1,822	517	(588)	16,579
Operating costs and expenses [(2)]	4,216	972	740	17	5,945
Net cash from settlement of commodity derivatives	—	—	—	(377)	(377)
Other (income) expense, net [(3)]	—	—	—	(2)	(2)
Net income (loss) attributable to noncontrolling interests	—	187	—	—	187
Total expenses and other	4,216	1,159	740	(362)	5,753
Total (gains) losses on derivatives, net included in marketing revenue, less net cash from settlement	—	—	4	—	4
Adjusted EBITDAX	$ 10,612	$ 663	$ (219)	$ (226)	$ 10,830
Net properties and equipment	$ 32,717	$ 6,697	$ —	$ 2,175	$ 41,589
Capital expenditures	$ 7,934	$ 1,149	$ —	$ 173	$ 9,256
Goodwill	$ 5,123	$ 453	$ —	$ —	$ 5,576

(1) Total revenues and other excludes gains (losses) on divestitures, net since these gains and losses are excluded from Adjusted EBITDAX.

(2) Operating costs and expenses excludes exploration expense, DD&A, impairments, restructuring charges, and other operating expense since these expenses are excluded from Adjusted EBITDAX.

(3) Other (income) expense, net excludes certain other nonoperating items since these items are excluded from Adjusted EBITDAX.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
YEARS ENDED DECEMBER 31, 2016, 2015, AND 2014

25. Segment Information (Continued)

The following represents Anadarko's sales revenues (based on the origin of the sales) and net properties and equipment by geographic area:

	Years Ended December 31,		
millions	**2016**	2015	2014
Sales Revenues			
United States	**$ 7,049**	$ 7,819	$ 13,083
Algeria	**1,103**	1,189	2,435
Other International	**295**	478	857
Total sales revenues	**$ 8,447**	$ 9,486	$ 16,375

	December 31,	
millions	**2016**	2015
Net Properties and Equipment		
United States	**$ 28,024**	$ 29,625
Algeria	**1,117**	1,271
Other International	**3,027**	2,855
Total net properties and equipment	**$ 32,168**	$ 33,751

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

The unaudited supplemental information on oil and gas exploration and production activities for 2016, 2015, and 2014 has been presented in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 932, *Extractive Activities—Oil and Gas* and the SEC's final rule, *Modernization of Oil and Gas Reporting*. Disclosures by geographic area include the United States and International. For 2016, the International geographic area consisted of proved reserves located in Algeria and Ghana. The Company sold its Chinese subsidiary during 2014.

Oil and Gas Reserves

The following reserves disclosures reflect estimates of proved reserves, proved developed reserves, and PUDs, net of third-party royalty interests, of oil, natural gas, and NGLs owned at each year end and changes in proved reserves during each of the last three years. Oil and NGLs volumes are presented in MMBbls and natural-gas volumes are presented in Bcf at a pressure base of 14.73 pounds per square inch. Total volumes are presented in MMBOE. For this computation, one barrel is the equivalent of 6,000 cubic feet of natural gas. Shrinkage associated with NGLs has been deducted from the natural-gas reserves volumes.

Reserves for international locations are calculated in accordance with the terms of governing agreements. The international reserves include estimated quantities allocated to Anadarko for recovery of costs and income taxes and Anadarko's net equity share after recovery of such costs.

The Company's estimates of proved reserves are made using available geological and reservoir data as well as production performance data. These estimates are reviewed annually by internal reservoir engineers and revised, either upward or downward, as warranted by additional data. The results of infill drilling are treated as positive revisions due to increases to expected recovery. Other revisions are due to changes in, among other things, development plans, reservoir performance, commodity prices, economic conditions, and governmental restrictions.

The prices below were used to compute the information presented in the following tables and are adjusted only for fixed and determinable amounts under provisions in existing contracts:

	Oil per Bbl	Natural Gas per MMBtu	NGLs per Bbl
December 31, 2016	$ 42.75	$ 2.48	$ 19.74
December 31, 2015	$ 50.28	$ 2.59	$ 19.47
December 31, 2014	$ 94.99	$ 4.35	$ 45.25

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Oil and Gas Reserves (Continued)

	Oil (MMBbls)			Natural Gas (Bcf)		
	United States	International	Total	United States	International	Total
Proved Reserves						
December 31, 2013	592	259	851	9,205	—	9,205
Revisions of prior estimates	167	18	185	710	31	741
Extensions, discoveries, and other additions	25	—	25	196	—	196
Purchases in place	—	—	—	—	—	—
Sales in place	(6)	(17)	(23)	(492)	—	(492)
Production	(74)	(35)	(109)	(951)	—	(951)
December 31, 2014	704	225	929	8,668	31	8,699
Revisions of prior estimates	2	(6)	(4)	(888)	4	(884)
Extensions, discoveries, and other additions	15	—	15	60	—	60
Purchases in place	—	—	—	8	—	8
Sales in place	(111)	—	(111)	(1,003)	—	(1,003)
Production	(85)	(31)	(116)	(854)	(5)	(859)
December 31, 2015	**525**	**188**	**713**	**5,991**	**30**	**6,021**
Revisions of prior estimates	**11**	**3**	**14**	**310**	**—**	**310**
Extensions, discoveries, and other additions	**24**	**—**	**24**	**59**	**—**	**59**
Purchases in place	**81**	**—**	**81**	**68**	**—**	**68**
Sales in place	**(14)**	**—**	**(14)**	**(1,263)**	**—**	**(1,263)**
Production	**(86)**	**(30)**	**(116)**	**(766)**	**(5)**	**(771)**
December 31, 2016	**541**	**161**	**702**	**4,399**	**25**	**4,424**
Proved Developed Reserves						
December 31, 2013	347	202	549	7,120	—	7,120
December 31, 2014	352	190	542	6,635	27	6,662
December 31, 2015	332	159	491	5,184	30	5,214
December 31, 2016	**360**	**147**	**507**	**3,637**	**25**	**3,662**
Proved Undeveloped Reserves						
December 31, 2013	245	57	302	2,085	—	2,085
December 31, 2014	352	35	387	2,033	4	2,037
December 31, 2015	193	29	222	807	—	807
December 31, 2016	**181**	**14**	**195**	**762**	**—**	**762**

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION
AND PRODUCTION ACTIVITIES
(Unaudited)

Oil and Gas Reserves (Continued)

	NGLs (MMBbls)			Total (MMBOE)		
	United States	International	Total	United States	International	Total
Proved Reserves						
December 31, 2013	395	12	407	2,521	271	2,792
Revisions of prior estimates [(1)]	129	2	131	414	25	439
Extensions, discoveries, and other additions	5	—	5	63	—	63
Purchases in place	—	—	—	—	—	—
Sales in place	(19)	—	(19)	(107)	(17)	(124)
Production	(44)	(1)	(45)	(276)	(36)	(312)
December 31, 2014	466	13	479	2,615	243	2,858
Revisions of prior estimates [(1)]	(99)	4	(95)	(245)	(1)	(246)
Extensions, discoveries, and other additions	4	—	4	29	—	29
Purchases in place	—	—	—	1	—	1
Sales in place	(1)	—	(1)	(279)	—	(279)
Production	(45)	(2)	(47)	(272)	(34)	(306)
December 31, 2015	**325**	**15**	**340**	**1,849**	**208**	**2,057**
Revisions of prior estimates [(1)]	**45**	**2**	**47**	**108**	**5**	**113**
Extensions, discoveries, and other additions	**6**	**—**	**6**	**40**	**—**	**40**
Purchases in place	**5**	**—**	**5**	**97**	**—**	**97**
Sales in place	**(69)**	**—**	**(69)**	**(294)**	**—**	**(294)**
Production	**(44)**	**(2)**	**(46)**	**(258)**	**(33)**	**(291)**
December 31, 2016	**268**	**15**	**283**	**1,542**	**180**	**1,722**
Proved Developed Reserves						
December 31, 2013	268	—	268	1,801	202	2,003
December 31, 2014	304	13	317	1,762	207	1,969
December 31, 2015	257	15	272	1,453	179	1,632
December 31, 2016	**193**	**15**	**208**	**1,159**	**166**	**1,325**
Proved Undeveloped Reserves						
December 31, 2013	127	12	139	720	69	789
December 31, 2014	162	—	162	853	36	889
December 31, 2015	68	—	68	396	29	425
December 31, 2016	**75**	**—**	**75**	**383**	**14**	**397**

(1) Revisions of prior estimates include the effects of new infill drilling, changes in commodity prices, and other updates, including changes in economic conditions, changes in reservoir performance, and changes to development plans. Additions generated by Anadarko's infill drilling programs were 69 MMBOE for 2016, 89 MMBOE for 2015, and 577 MMBOE for 2014.

ANADARKO PETROLEUM CORPORATION
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Total proved reserves decreased by 335 MMBOE in 2016 primarily due to the following:

Revisions of prior estimates Prior estimates of proved reserves were revised upward by 113 MMBOE.

MMBOE	**December 31, 2016**
Revisions due to changes in year-end prices (price impact to opening balance)	(147)
Other revisions of prior estimates	
Revisions due to performance	74
Revisions due to cost reductions	100
Revisions due to successful infill drilling	69
Revisions due to development plan updates	(3)
Other revisions	20
Total other revisions of prior estimates	260
Revisions of prior estimates	113

Negative revisions of 147 MMBOE were due to the decline in commodity prices. The negative price-related revisions were offset by a net increase of 260 MMBOE associated with the following:

- *Performance* The Company experienced an increase of 74 MMBOE in proved reserves. Upward revisions of 102 MMBOE are primarily due to improved well performance in the DJ basin, certain U.S. shale plays, and select wells in the Gulf of Mexico. Downward revisions of 28 MMBOE are primarily due to performance updates associated with select wells in the Gulf of Mexico.

- *Cost reductions* Ongoing cost-optimization efforts, and a reduced cost structure associated with the lower commodity-price environment resulted in an increase in proved reserves. The Eagleford and the DJ basin areas experienced an increase of 94 MMBOE of proved reserves associated with certain wells, included in the negative price-related revisions, which experienced restored economic producibility upon reduction of the cost structure. The remaining increase in proved reserves due to the improved cost structure is attributable to numerous areas across the Company.

- *Infill drilling activities* The Company added 69 MMBOE of proved reserves associated with infill drilling activities, the majority of which were in the DJ basin and the K2 and Caesar/Tonga areas of the Gulf of Mexico.

- *Other revisions* Other revisions resulted from the Company's multi-step reserves reconciliation process and the elimination of duplicative adjustments to the opening reserves balance.

Extensions and discoveries Proved reserves increased by 40 MMBOE through the extension of proved acreage, primarily as a result of successful drilling in the Delaware basin. Although shale plays represented only 20% of the Company's total proved reserves at December 31, 2016, growth in the shale plays contributed a majority of the total extensions and discoveries.

Purchases in place Proved reserves increased by 97 MMBOE due to the GOM Acquisition. The increase is comprised of 67 MMBOE of proved developed reserves and 30 MMBOE of PUDs.

Sales in place Proved reserves decreased by 294 MMBOE due to the divestiture of certain U.S. onshore properties. The decrease is comprised of 279 MMBOE of proved developed reserves and 15 MMBOE of PUDs.

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Total proved reserves decreased by 801 MMBOE in 2015 primarily due to the following:

Revisions of prior estimates Prior estimates of proved reserves were revised downward by 246 MMBOE.

MMBOE	**December 31, 2015**
Revisions due to changes in year-end prices (price impact to opening balance)	(624)
Other revisions of prior estimates	
Revisions due to performance	222
Revisions due to cost reductions	139
Revisions due to successful infill drilling	89
Revisions due to development plan updates	(126)
Other revisions	54
Total other revisions of prior estimates	378
Revisions of prior estimates	(246)

Negative revisions of 624 MMBOE were due to the decline in commodity prices and include a reduction to NGLs reserves of 43 MMBOE associated with price-induced ethane rejection. The negative price-related revisions were partially offset by a net increase of 378 MMBOE associated with the following:

- *Performance* The Company experienced an increase of 169 MMBOE in proved reserves due primarily to increases to planned lateral lengths in the Eagleford area of South Texas combined with improved well performance in the Eagleford area, the DJ basin, and the Marcellus area of the Appalachian basin. All other performance increases are a result of minor improvements from numerous areas throughout the Company.
- *Cost reductions* Capital spent in 2015 associated with ongoing drilling and completion activities, ongoing cost-optimization efforts, and a reduced cost structure associated with the lower commodity-price environment resulted in an increase in proved reserves. The DJ basin and Greater Natural Buttes areas and the Eagleford area experienced an increase of 81 MMBOE of proved reserves due to drilling activity associated with certain wells, included in the negative price-related revisions, which experienced restored economic producibility upon reduction of the capital cost structure. An increase of 14 MMBOE in proved reserves is associated with the Marcellus area where certain wells, included in the negative price-related revisions, experienced extended economic limits as a result of reductions to operating expenses during 2015. The remaining increase in proved reserves due to the improved cost structure is attributable to numerous areas across the Company.
- *Infill drilling activities* The Company added 89 MMBOE of proved reserves associated with infill drilling activities during 2015, the majority of which were in the DJ basin.
- *Development plan updates* The majority of revisions associated with updates to development plans occurred in the DJ basin due to a significantly reduced development pace related to the decrease in commodity prices.
- *Other revisions* Other revisions resulted from the Company's multi-step reserves reconciliation process and the elimination of duplicative adjustments to the opening reserves balance.

Extensions and discoveries Proved reserves increased by 29 MMBOE through the extension of proved acreage, primarily as a result of successful drilling in the Delaware basin. Although shale plays represented only 20% of the Company's total proved reserves at December 31, 2015, growth in the shale plays contributed almost all of the total extensions and discoveries.

Sales in place Proved developed reserves decreased by 238 MMBOE primarily associated with the divestiture of a portion of the Company's East Texas assets and EOR and coalbed methane assets. PUDs decreased by 41 MMBOE primarily associated with divestiture activities in the U.S. onshore.

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Total proved reserves increased by 66 MMBOE in 2014 primarily due to the following:

Revisions of prior estimates Prior estimates of proved reserves were revised upward by 439 MMBOE.

MMBOE	**December 31, 2014**
Revisions due to changes in year-end prices (price impact to opening balance)	(1)
Other revisions of prior estimates	
Revisions due to performance	42
Revisions due to successful infill drilling	577
Revisions due to development plan updates	(179)
Total other revisions of prior estimates	440
Revisions of prior estimates	439

Positive revisions of 439 MMBOE were associated with the following:

- *Performance* The Company experienced an increase in proved reserves primarily due to improved well performance in the DJ basin as well as in certain shale and international assets.
- *Infill drilling activities* The Company added 577 MMBOE of proved reserves associated with infill drilling primarily in large onshore areas such as the DJ basin and the Eagleford and Haynesville shales.
- *Development plan updates* The majority of the revisions associated with updates to development plans occurred in the DJ basin due to the optimization of horizontal drilling locations and the discontinuation of vertical well workover plans.

Extensions and discoveries Proved reserves increased by 63 MMBOE primarily as a result of successful drilling in the Marcellus and Delaware basin shale plays. Although shale plays represented only 17% of the Company's total proved reserves at December 31, 2014, growth in the shale plays contributed 49 MMBOE, or 78%, of the total extensions and discoveries.

Sales in place Proved developed reserves decreased by 69 MMBOE and PUDs decreased by 55 MMBOE due to divestitures, including the divestiture of the Company's interest in the Pinedale/Jonah assets in Wyoming, the Company's Chinese subsidiary, and a portion of the Company's working interest in the East Texas Chalk area.

ANADARKO PETROLEUM CORPORATION
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Capitalized Costs

Capitalized costs include the cost of properties, equipment, and facilities for oil and natural-gas producing activities. Capitalized costs for proved properties include costs for oil and natural-gas leaseholds where proved reserves have been identified, development wells, and related equipment and facilities, including development wells in progress. Capitalized costs for unproved properties include costs for acquiring oil and gas leaseholds where no proved reserves have been identified, including costs of exploratory wells that are in the process of drilling or in active completion, and costs of exploratory wells suspended or waiting on completion. Capitalized costs associated with activities of the Company's midstream and marketing reporting segments, LNG facilities costs, and other corporate activities are not included.

millions	United States	International	Total
December 31, 2016			
Capitalized			
Unproved properties	**$ 3,332**	**$ 804**	**$ 4,136**
Proved properties	**47,476**	**5,752**	**53,228**
	50,808	**6,556**	**57,364**
Less accumulated DD&A	**30,675**	**2,655**	**33,330**
Net capitalized costs	**$ 20,133**	**$ 3,901**	**$ 24,034**
December 31, 2015			
Capitalized			
Unproved properties	$ 2,742	$ 739	$ 3,481
Proved properties	50,275	5,472	55,747
	53,017	6,211	59,228
Less accumulated DD&A	31,366	2,281	33,647
Net capitalized costs	$ 21,651	$ 3,930	$ 25,581

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Costs Incurred in Oil and Gas Property Acquisition, Exploration, and Development

Amounts reported as costs incurred include both capitalized costs and costs charged to expense when incurred for oil and gas property acquisition, exploration, and development activities. Costs incurred also include new AROs established in the current year as well as increases or decreases to the AROs resulting from changes to cost estimates during the year. Exploration costs presented below include the costs of drilling and equipping successful and unsuccessful exploration wells during the year, geological and geophysical expenses, and the costs of retaining undeveloped leaseholds. Development costs include the costs of drilling and equipping development wells, and construction of related production facilities. Costs associated with activities of the Company's midstream and marketing reporting segments, LNG facilities costs, and other corporate activities are not included.

millions	United States	International	Total
Year Ended December 31, 2016			
Property acquisitions			
Unproved	**$ 178**	**$ 9**	**$ 187**
Proved	**2,498**	**—**	**2,498**
Exploration	**398**	**433**	**831**
Development	**1,780**	**337**	**2,117**
Total costs incurred	**$ 4,854**	**$ 779**	**$ 5,633**
Year Ended December 31, 2015			
Property acquisitions			
Unproved	$ 293	$ 1	$ 294
Proved	81	—	81
Exploration	503	609	1,112
Development	3,660	606	4,266
Total costs incurred	$ 4,537	$ 1,216	$ 5,753
Year Ended December 31, 2014			
Property acquisitions			
Unproved	$ 264	$ 19	$ 283
Proved	3	—	3
Exploration	1,095	616	1,711
Development	6,158	557	6,715
Total costs incurred	$ 7,520	$ 1,192	$ 8,712

ANADARKO PETROLEUM CORPORATION
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(Unaudited)

Results of Operations

Results of operations for producing activities consist of all activities within the oil and gas exploration and production reporting segment. Net revenues from production include only the revenues from the production and sale of oil, natural gas, and NGLs. Gains (losses) on property dispositions represent net gains or losses on sales of oil and gas properties. Production costs are costs to operate and maintain the Company's wells, related equipment, and supporting facilities used in oil and gas operations, including labor; well service and repair; location maintenance; power and fuel; gathering; processing; transportation; production, property, and other taxes; and production-related general and administrative costs. Exploration expenses include dry hole costs, leasehold impairments, geological and geophysical expenses, and the costs of retaining unproved leaseholds. Other operating expense includes Deepwater Horizon settlement and related costs. Income tax expense is calculated by applying the current statutory tax rates to the revenues after deducting costs, which include DD&A allowances, after giving effect to permanent differences. The results of operations exclude general office overhead and interest expense attributable to oil and gas activities.

millions	United States	International	Total
Year Ended December 31, 2016			
Net revenues from production			
Third-party sales	$ 3,884	$ 619	$ 4,503
Sales to consolidated affiliates	1,871	779	2,650
Gains (losses) on property dispositions	(855)	(6)	(861)
	4,900	1,392	6,292
Production costs			
Oil and gas operating	607	204	811
Oil and gas transportation	964	38	1,002
Production-related general and administrative expenses	317	20	337
Production, property, and other taxes	189	282	471
	2,077	544	2,621
Exploration expenses	541	405	946
DD&A	3,512	395	3,907
Impairments related to oil and gas properties	55	—	55
Other operating expense	62	49	111
	(1,347)	(1)	(1,348)
Income tax expense (benefit)	(494)	155	(339)
Results of operations	$ (853)	$ (156)	$ (1,009)

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Results of Operations (Continued)

millions	United States	International	Total
Year Ended December 31, 2015			
Net revenues from production			
Third-party sales	$ 4,409	$ 673	$ 5,082
Sales to consolidated affiliates	2,184	994	3,178
Gains (losses) on property dispositions	(976)	(14)	(990)
	5,617	1,653	7,270
Production costs			
Oil and gas operating	815	199	1,014
Oil and gas transportation	1,083	34	1,117
Production-related general and administrative expenses	398	11	409
Production, property, and other taxes	218	270	488
	2,514	514	3,028
Exploration expenses	1,447	1,197	2,644
DD&A	3,785	399	4,184
Impairments related to oil and gas properties	4,033	—	4,033
Other operating expense	150	—	150
	(6,312)	(457)	(6,769)
Income tax expense (benefit)	(2,332)	252	(2,080)
Results of operations	$ (3,980)	$ (709)	$ (4,689)
Year Ended December 31, 2014			
Net revenues from production			
Third-party sales	$ 7,425	$ 1,518	$ 8,943
Sales to consolidated affiliates	4,453	1,773	6,226
Gains (losses) on property dispositions	(91)	1,982	1,891
	11,787	5,273	17,060
Production costs			
Oil and gas operating	968	203	1,171
Oil and gas transportation	1,084	33	1,117
Production-related general and administrative expenses	394	32	426
Production, property, and other taxes	652	535	1,187
	3,098	803	3,901
Exploration expenses	1,218	421	1,639
DD&A	3,783	398	4,181
Impairments related to oil and gas properties	821	—	821
Other operating expense	163	—	163
	2,704	3,651	6,355
Income tax expense (benefit)	995	979	1,974
Results of operations	$ 1,709	$ 2,672	$ 4,381

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

Estimates of future net cash flows from proved reserves are computed based on the average beginning-of-the-month prices during the 12-month period for the year. Estimated future net cash flows for all periods presented are reduced by estimated future development, production, and abandonment and dismantlement costs based on existing costs, assuming continuation of existing economic conditions, and by estimated future income tax expense. These estimates also include assumptions about the timing of future production of proved reserves, and timing of future development, production costs, and abandonment and dismantlement. Income tax expense, both U.S. and foreign, is calculated by applying the existing statutory tax rates, including any known future changes, to the pretax net cash flows, giving effect to any permanent differences and reduced by the applicable tax basis. The effect of tax credits is considered in determining the income tax expense. The 10% discount factor is prescribed by GAAP.

The present value of future net cash flows is not an estimate of the fair value of Anadarko's oil and gas properties. An estimate of fair value would also take into account, among other things, anticipated changes in future prices and costs, the expected recovery of reserves in excess of proved reserves, and a discount factor more representative of the time value of money and the risks inherent in producing oil and natural gas. Significant changes in estimated reserves volumes or commodity prices could have a material effect on the Company's Consolidated Financial Statements.

millions	United States	International	Total
December 31, 2016			
Future cash inflows	**$ 33,513**	**$ 7,328**	**$ 40,841**
Future production costs	**16,921**	**3,290**	**20,211**
Future development costs	**7,292**	**566**	**7,858**
Future income tax expenses	**2,606**	**1,408**	**4,014**
Future net cash flows	**6,694**	**2,064**	**8,758**
10% annual discount for estimated timing of cash flows	**1,658**	**470**	**2,128**
Standardized measure of discounted future net cash flows	**$ 5,036**	**$ 1,594**	**$ 6,630**
December 31, 2015			
Future cash inflows	$ 42,919	$ 10,392	$ 53,311
Future production costs	21,100	3,829	24,929
Future development costs	7,209	637	7,846
Future income tax expenses	4,146	2,423	6,569
Future net cash flows	10,464	3,503	13,967
10% annual discount for estimated timing of cash flows	3,372	910	4,282
Standardized measure of discounted future net cash flows	$ 7,092	$ 2,593	$ 9,685
December 31, 2014			
Future cash inflows	$ 114,384	$ 23,795	$ 138,179
Future production costs	36,390	6,061	42,451
Future development costs	14,794	1,356	16,150
Future income tax expenses	21,813	6,968	28,781
Future net cash flows	41,387	9,410	50,797
10% annual discount for estimated timing of cash flows	17,239	2,898	20,137
Standardized measure of discounted future net cash flows	$ 24,148	$ 6,512	$ 30,660

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

millions	United States	International	Total
2016			
Balance at January 1	**$ 7,092**	**$ 2,593**	**$ 9,685**
Sales and transfers of oil and gas produced, net of production costs	**(3,678)**	**(856)**	**(4,534)**
Net changes in prices and production costs	**(1,953)**	**(1,607)**	**(3,560)**
Changes in estimated future development costs	**742**	**(126)**	**616**
Extensions, discoveries, additions, and improved recovery, less related costs	**429**	**—**	**429**
Development costs incurred during the period	**1,223**	**203**	**1,426**
Revisions of previous quantity estimates	**1,388**	**320**	**1,708**
Purchases of minerals in place	**193**	**—**	**193**
Sales of minerals in place	**(1,277)**	**—**	**(1,277)**
Accretion of discount	**949**	**431**	**1,380**
Net change in income taxes	**690**	**717**	**1,407**
Other	**(762)**	**(81)**	**(843)**
Balance at December 31	**$ 5,036**	**$ 1,594**	**$ 6,630**
2015			
Balance at January 1	$ 24,148	$ 6,512	$ 30,660
Sales and transfers of oil and gas produced, net of production costs	(4,079)	(1,153)	(5,232)
Net changes in prices and production costs	(28,967)	(8,010)	(36,977)
Changes in estimated future development costs	4,408	221	4,629
Extensions, discoveries, additions, and improved recovery, less related costs	219	—	219
Development costs incurred during the period	2,311	379	2,690
Revisions of previous quantity estimates	(1,890)	47	(1,843)
Purchases of minerals in place	30	—	30
Sales of minerals in place	(2,262)	—	(2,262)
Accretion of discount	3,648	1,143	4,791
Net change in income taxes	9,940	3,193	13,133
Other	(414)	261	(153)
Balance at December 31	$ 7,092	$ 2,593	$ 9,685

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL INFORMATION ON OIL AND GAS EXPLORATION AND PRODUCTION ACTIVITIES
(Unaudited)

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (Continued)

millions	United States	International	Total
2014			
Balance at January 1	$ 21,169	$ 7,937	$ 29,106
Sales and transfers of oil and gas produced, net of production costs	(8,780)	(2,492)	(11,272)
Net changes in prices and production costs	(3,981)	(1,984)	(5,965)
Changes in estimated future development costs	(4,180)	(250)	(4,430)
Extensions, discoveries, additions, and improved recovery, less related costs	963	—	963
Development costs incurred during the period	2,591	279	2,870
Revisions of previous quantity estimates	13,703	1,921	15,624
Purchases of minerals in place	—	—	—
Sales of minerals in place	(591)	(696)	(1,287)
Accretion of discount	3,221	1,341	4,562
Net change in income taxes	(1,294)	549	(745)
Other	1,327	(93)	1,234
Balance at December 31	$ 24,148	$ 6,512	$ 30,660

ANADARKO PETROLEUM CORPORATION
SUPPLEMENTAL QUARTERLY INFORMATION
(Unaudited)

Quarterly Financial Data

The following summarizes quarterly financial data for 2016 and 2015:

millions except per-share amounts	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2016				
Sales revenues	**$ 1,634**	**$ 1,985**	**$ 2,251**	**$ 2,577**
Gains (losses) on divestitures and other, net	**40**	**(70)**	**(358)**	**(190)**
Impairments	**16**	**18**	**27**	**166**
Operating income (loss)	**(864)**	**(332)**	**(793)**	**(610)**
Net income (loss)	**(998)**	**(611)**	**(747)**	**(452)**
Net income (loss) attributable to noncontrolling interests	**36**	**81**	**83**	**63**
Net income (loss) attributable to common stockholders	**(1,034)**	**(692)**	**(830)**	**(515)**
Earnings per share				
Net income (loss) attributable to common stockholders—basic	**$ (2.03)**	**$ (1.36)**	**$ (1.61)**	**$ (0.94)**
Net income (loss) attributable to common stockholders—diluted	**$ (2.03)**	**$ (1.36)**	**$ (1.61)**	**$ (0.94)**
Average number common shares outstanding—basic	**509**	**510**	**517**	**551**
Average number common shares outstanding—diluted	**509**	**510**	**517**	**551**
2015				
Sales revenues	$ 2,585	$ 2,637	$ 2,230	$ 2,034
Gains (losses) on divestitures and other, net	(264)	(1)	(542)	19
Impairments	2,783	30	758	1,504
Operating income (loss)	(4,208)	90	(2,549)	(2,142)
Net income (loss)	(3,236)	108	(2,160)	(1,524)
Net income (loss) attributable to noncontrolling interests	32	47	75	(274)
Net income (loss) attributable to common stockholders	(3,268)	61	(2,235)	(1,250)
Earnings per share				
Net income (loss) attributable to common stockholders—basic	$ (6.45)	$ 0.12	$ (4.41)	$ (2.45)
Net income (loss) attributable to common stockholders—diluted	$ (6.45)	$ 0.12	$ (4.41)	$ (2.45)
Average number common shares outstanding—basic	507	508	508	508
Average number common shares outstanding—diluted	507	509	508	508

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

EVALUATION AND DISCLOSURE CONTROLS AND PROCEDURES

Anadarko's Chief Executive Officer and Chief Financial Officer performed an evaluation of the Company's disclosure controls and procedures as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended. The Company's disclosure controls and procedures are designed to ensure that information required to be disclosed by the Company in reports it files or submits under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the SEC, and to ensure that the information required to be disclosed by the Company in reports that it files or submits under the Securities Exchange Act of 1934, as amended, is accumulated and communicated to the Company's management, including the principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that the Company's disclosure controls and procedures are effective as of December 31, 2016.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

See *Management's Assessment of Internal Control Over Financial Reporting* under Item 8 of this Form 10-K.

ATTESTATION REPORT OF THE REGISTERED PUBLIC ACCOUNTING FIRM

See *Report of Independent Registered Public Accounting Firm* under Item 8 of this Form 10-K.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There were no changes in Anadarko's internal control over financial reporting during the fourth quarter of 2016 that materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting. See *Management's Assessment of Internal Control Over Financial Reporting* under Item 8 of this Form 10-K.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers, and Corporate Governance

See *Anadarko Board of Directors, Corporate Governance—Committees of the Board, Corporate Governance—Board of Directors,* and *Section 16(a) Beneficial Ownership Reporting Compliance* in the Definitive Proxy Statement (Proxy Statement) for the Annual Meeting of Stockholders of Anadarko Petroleum Corporation to be held May 10, 2017 (to be filed with the SEC prior to March 31, 2017), each of which is incorporated herein by reference.

See list of *Executive Officers of the Registrant* under Items 1 and 2 of this Form 10-K, which is incorporated herein by reference.

The Company's Code of Business Conduct and Ethics and the Code of Ethics for the Chief Executive Officer, Chief Financial Officer, and Chief Accounting Officer (Code of Ethics) can be found on the Company's website located at www.anadarko.com/Responsibility/Good-Governance. Any stockholder may request a printed copy of the Code of Ethics by submitting a written request to the Company's Corporate Secretary. If the Company amends the Code of Ethics or grants a waiver, including an implicit waiver, from the Code of Ethics, the Company will disclose the information on its website. The waiver information will remain on the website for at least 12 months after the initial disclosure of such waiver.

Item 11. Executive Compensation

See *Corporate Governance—Board of Directors—Compensation and Benefits Committee Interlocks and Insider Participation, Corporate Governance—Board of Directors—Director Compensation, Corporate Governance—Director Compensation Table for 2016, Compensation and Benefits Committee Report on 2016 Executive Compensation, Compensation Discussion and Analysis,* and *Executive Compensation* in the Proxy Statement, each of which is incorporated herein by reference. The Compensation and Benefits Committee Report and related information incorporated by reference herein shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filing.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

See *Security Ownership of Certain Beneficial Owners and Management* in the Proxy Statement and *Securities Authorized for Issuance under Equity Compensation Plans* under Item 5 of this Form 10-K, each of which is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions, and Director Independence

See *Corporate Governance—Board of Directors* and *Transactions with Related Persons* in the Proxy Statement, each of which is incorporated herein by reference.

Item 14. Principal Accounting Fees and Services

See *Independent Auditor* in the Proxy Statement, which is incorporated herein by reference.

PART IV

Item 15. Exhibits, Financial Statement Schedules

a) EXHIBITS

The following documents are filed as part of this Form 10-K or incorporated by reference:

(1) The Consolidated Financial Statements of Anadarko Petroleum Corporation are listed on the Index to this Form 10-K, page 82.

(2) Exhibits not incorporated by reference to a prior filing are designated by an asterisk (*) and are filed herewith or double asterisk (**) and are furnished herewith; all exhibits not so designated are incorporated herein by reference to a prior filing under File Number 1-8968 as indicated.

Exhibit Number	Description
2 (i)	Agreement and Plan of Merger dated as of June 22, 2006, among Anadarko Petroleum Corporation, APC Acquisition Sub, Inc. and Kerr-McGee Corporation, filed as Exhibit 2.2 to Form 8-K filed on June 26, 2006
3 (i)	Restated Certificate of Incorporation of Anadarko Petroleum Corporation, dated May 21, 2009, filed as Exhibit 3.3 to Form 8-K filed on May 22, 2009
(ii)	By-Laws of Anadarko Petroleum Corporation, amended and restated as of September 15, 2015, filed as Exhibit 3.1 to Form 8-K filed on September 21, 2015
4 (i)	Trustee Indenture, dated as of September 19, 2006, Anadarko Petroleum Corporation to The Bank of New York Trust Company, N.A., filed as Exhibit 4.1 to Form 8-K filed on September 19, 2006
(ii)	Third Supplemental Indenture, dated as of June 10, 2015, between Anadarko Petroleum Corporation and The Bank of New York Mellon Trust Company, N.A., filed as Exhibit 4.2 to Form 8-K filed on June 10, 2015
(iii)	Second Supplemental Indenture dated October 4, 2006, among Anadarko Petroleum Corporation, Kerr-McGee Corporation, and Citibank, N.A., filed as Exhibit 4.1 to Form 8-K filed on October 6, 2006
(iv)	Ninth Supplemental Indenture dated October 4, 2006, among Anadarko Petroleum Corporation, Kerr-McGee Corporation, and Citibank, N.A., filed as Exhibit 4.2 to Form 8-K filed on October 6, 2006
(v)	Officers' Certificate of Anadarko Petroleum Corporation, dated March 2, 2009, establishing the 7.625% Senior Notes due 2014 and the 8.700% Senior Notes due 2019, filed as Exhibit 4.1 to Form 8-K filed on March 6, 2009
(vi)	Form of 8.700% Senior Notes due 2019, filed as Exhibit 4.3 to Form 8-K filed on March 6, 2009
(vii)	Officers' Certificate of Anadarko Petroleum Corporation, dated June 9, 2009, establishing the 5.75% Senior Notes due 2014, the 6.95% Senior Notes due 2019 and the 7.95% Senior Notes due 2039, filed as Exhibit 4.1 to Form 8-K filed on June 12, 2009
(viii)	Form of 6.95% Senior Notes due 2019, filed as Exhibit 4.3 to Form 8-K filed on June 12, 2009
(ix)	Form of 7.95% Senior Notes due 2039, filed as Exhibit 4.4 to Form 8-K filed on June 12, 2009
(x)	Officers' Certificate of Anadarko Petroleum Corporation dated March 9, 2010, establishing the 6.200% Senior Notes due 2040, filed as Exhibit 4.1 to Form 8-K filed on March 16, 2010

	Exhibit Number	Description
	4 (xi)	Form of 6.200% Senior Notes due 2040, filed as Exhibit 4.2 to Form 8-K filed on March 16, 2010
	(xii)	Officers' Certificate of Anadarko Petroleum Corporation dated August 9, 2010, establishing the 6.375% Senior Notes due 2017, filed as Exhibit 4.1 to Form 8-K filed on August 12, 2010
	(xiii)	Form of 6.375% Senior Notes due 2017, filed as Exhibit 4.2 to Form 8-K filed on August 12, 2010
	(xiv)	Officers' Certificate of Anadarko Petroleum Corporation dated July 7, 2014, establishing the 3.45% Senior Notes due 2024 and the 4.50% Senior Notes due 2044, filed as Exhibit 4.1 to Form 8-K filed on July 7, 2014
	(xv)	Form of 3.45% Senior Notes due 2024, filed as Exhibit 4.2 to Form 8-K filed on July 7, 2014
	(xvi)	Form of 4.50% Senior Notes due 2044, filed as Exhibit 4.3 to Form 8-K filed on July 7, 2014
	(xvii)	Purchase Contract Agreement, dated June 10, 2015, between Anadarko Petroleum Corporation and The Bank of New York Mellon Trust Company, N.A., filed as Exhibit 4.1 to Form 8-K filed on June 10, 2015
	(xviii)	Form of Unit (included in Exhibit 4.xvii)
	(xix)	Form of Purchase Contract (included in Exhibit 4.xvii)
	(xx)	Form of Amortizing Note (included in Exhibit 4.ii)
	(xxi)	Officers' Certificate of Anadarko Petroleum Corporation dated March 17, 2016, establishing the 4.85% Senior Notes due 2021 and the 5.55% Senior Notes due 2026, and the 6.60% Senior Notes due 2046, filed as Exhibit 4.1 to Form 8-K filed on March 17, 2016
	(xxii)	Form of 4.85% Senior Notes due 2021, filed as Exhibit 4.2 to Form 8-K filed on March 17, 2016
	(xxiii)	Form of 5.55% Senior Notes due 2026, filed as Exhibit 4.3 to Form 8-K filed on March 17, 2016
	(xxiv)	Form of 6.60% Senior Notes due 2046, filed as Exhibit 4.4 to Form 8-K filed on March 17, 2016
†	10 (i)	1998 Director Stock Plan of Anadarko Petroleum Corporation, effective January 30, 1998, filed as Appendix A to DEF 14A filed on March 16, 1998
†	(ii)	Form of Anadarko Petroleum Corporation 1998 Director Stock Plan Stock Option Agreement, filed as Exhibit 10.1 to Form 8-K filed on November 17, 2005
†	(iii)	Anadarko Petroleum Corporation Amended and Restated 1999 Stock Incentive Plan, filed as Appendix A to DEF 14A filed on March 18, 2005
†	(iv)	Form of Anadarko Petroleum Corporation Executive 1999 Stock Incentive Plan Stock Option Agreement, filed as Exhibit 10.2 to Form 8-K filed on November 17, 2005
†	(v)	Form of Anadarko Petroleum Corporation Non-Executive 1999 Stock Incentive Plan Stock Option Agreement, filed as Exhibit 10.3 to Form 8-K filed on November 17, 2005
†	(vi)	Form of Stock Option Agreement—1999 Stock Incentive Plan (UK Nationals), filed as Exhibit 10.4 to Form 8-K filed on November 17, 2005
†	(vii)	Amendment to Stock Option Agreement Under the Anadarko Petroleum Corporation 1999 Stock Incentive Plan, filed as Exhibit 10.1 to Form 8-K filed on January 23, 2007
†	(viii)	Anadarko Petroleum Corporation 1999 Stock Incentive Plan (Amendment to Performance Unit Agreement), filed as Exhibit 10.3 to Form 8-K filed on November 13, 2007
†	(ix)	Form of Anadarko Petroleum Corporation 1999 Stock Incentive Plan Restricted Stock Agreement, filed as Exhibit 10(b)(xxiv) to Form 10-K for year ended December 31, 1999, filed on March 16, 2000
†	(x)	Form of Anadarko Petroleum Corporation 1999 Stock Incentive Plan Restricted Stock Unit Award Letter, filed as Exhibit 10.1 to Form 8-K filed on November 13, 2007

	Exhibit Number	Description
†	10 (xi)	The Approved UK Sub-Plan of the Anadarko Petroleum Corporation 1999 Stock Incentive Plan, filed as Exhibit 10(b)(xxiv) to Form 10-K for year ended December 31, 2003, filed on March 4, 2004
†	(xii)	Key Employee Change of Control Contract, filed as Exhibit 10(b)(xxii) to Form 10-K for year ended December 31, 1997, filed on March 18, 1998
†	(xiii)	First Amendment to Anadarko Petroleum Corporation Key Employee Change of Control Contract, filed as Exhibit 10(b) to Form 10-Q for quarter ended September 30, 2000, filed on November 13, 2000
†	(xiv)	Form of Amendment to Anadarko Petroleum Corporation Key Employee Change of Control Contract, filed as Exhibit 10(b)(ii) to Form 10-Q for quarter ended June 30, 2003, filed on August 11, 2003
†	(xv)	Form of Key Employee Change of Control Contract (2011), filed as Exhibit 10(i) to Form 10-Q for quarter ended June 30, 2011, filed on July 27, 2011
†	(xvi)	Form of Amendment to Anadarko Petroleum Corporation Key Employee Change of Control Contract (Applicable to Vice Presidents Other Than Executive Officers as of October 2013), filed as Exhibit 10(ii) to Form 10-Q for quarter ended March 31, 2015, filed on May 4, 2015
†*	(xvii)	Form of Anadarko Petroleum Corporation Key Employee Change of Control Contract for Executive Vice Presidents
†	(xviii)	Letter Agreement regarding Post-Retirement Benefits, dated February 16, 2004—Robert J. Allison, Jr., filed as Exhibit 10(b)(xxxiv) to Form 10-K for year ended December 31, 2003, filed on March 4, 2004
†	(xix)	Anadarko Petroleum Corporation Savings Restoration Plan (As Amended and Restated Effective January 1, 2007), filed as Exhibit 10(xxii) to Form 10-K for year ended December 31, 2009, filed on February 23, 2010
†	(xx)	First Amendment, dated July 1, 2010, to the Anadarko Petroleum Corporation Savings Restoration Plan (As Amended and Restated Effective January 1, 2007), filed as Exhibit 10 (xviii) to Form 10-K for year ended December 31, 2014, filed on February 20, 2015
†	(xxi)	Second Amendment, dated November 30, 2011, to the Anadarko Petroleum Corporation Savings Restoration Plan (As Amended and Restated Effective January 1, 2007), filed as Exhibit 10(xix) to Form 10-K for year ended December 31, 2014, filed on February 20, 2015
†	(xxii)	Third Amendment, dated December 18, 2014, to the Anadarko Petroleum Corporation Savings Restoration Plan (As Amended and Restated Effective January 1, 2007), filed as Exhibit 10 (xx) to Form 10-K for year ended December 31, 2014, filed on February 20, 2015
†	(xxiii)	Anadarko Retirement Restoration Plan (As Amended and Restated Effective as of November 7, 2007), filed as Exhibit 10.2 to Form 8-K filed on November 13, 2007
†	(xxiv)	First Amendment, dated November 30, 2011, to the Anadarko Retirement Restoration Plan (As Amended and Restated Effective January 1, 2007), filed as Exhibit 10(xxii) to Form 10-K for year ended December 31, 2014, filed on February 20, 2015
†	(xxv)	Anadarko Petroleum Corporation Estate Enhancement Program, filed as Exhibit 10(b)(xxxiv) to Form 10-K for year ended December 31, 1998, filed on March 15, 1999
†	(xxvi)	Estate Enhancement Program Agreement between Anadarko Petroleum Corporation and Eligible Executives, filed as Exhibit 10(b)(xxxv) to Form 10-K for year ended December 31, 1998, filed on March 15, 1999
†	(xxvii)	Estate Enhancement Program Agreements effective November 29, 2000, filed as Exhibit 10(b) (xxxxii) to Form 10-K for year ended December 31, 2000, filed on March 15, 2001
†	(xxviii)	Anadarko Petroleum Corporation Management Life Insurance Plan, restated November 1, 2002, filed as Exhibit 10(b)(xxxii) to Form 10-K for year ended December 31, 2002, filed on March 14, 2003

	Exhibit Number	Description
†	10 (xxix)	First Amendment to Anadarko Petroleum Corporation Management Life Insurance Plan, effective June 30, 2003, filed as Exhibit 10(b)(xliii) to Form 10-K for year ended December 31, 2003, filed on March 4, 2004
†	(xxx)	Second Amendment to Anadarko Petroleum Corporation Management Life Insurance Plan, effective January 1, 2008, filed as Exhibit 10(xxix) to Form 10-K for year ended December 31, 2009, filed on February 23, 2010
†	(xxxi)	Anadarko Petroleum Corporation Officer Severance Plan, filed as Exhibit 10(b)(iv) to Form 10-Q for quarter ended September 30, 2003, filed on November 12, 2003
†	(xxxii)	Form of Termination Agreement and Release of All Claims Under Officer Severance Plan, filed as Exhibit 10.1 to Form 8-K filed on August 24, 2016
†	(xxxiii)	Form of Director and Officer Indemnification Agreement, filed as Exhibit 10 to Form 8-K filed on September 3, 2004
†	(xxxiv)	Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan, effective as of May 20, 2008, filed as Exhibit 10.1 to Form 8-K filed on May 27, 2008
†	(xxxv)	Form of Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan Stock Option Award Agreement, filed as Exhibit 10.3 to Form 8-K filed on November 13, 2009
†	(xxxvi)	Form of Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan Restricted Stock Unit Award Agreement, filed as Exhibit 10.1 to Form 8-K filed on November 13, 2009
†	(xxxvii)	Form of Anadarko Petroleum Corporation 2008 Omnibus Incentive Compensation Plan Performance Unit Award Agreement, filed as Exhibit 10.2 to Form 8-K filed on November 13, 2009
†	(xxxviii)	Anadarko Petroleum Corporation 2008 Director Compensation Plan, effective as of May 20, 2008, filed as Exhibit 10.2 to Form 8-K filed on May 27, 2008
†	(xxxix)	First Amendment to Anadarko Petroleum Corporation 2008 Director Compensation Plan, dated February 8, 2016, filed as Exhibit 10(xli) to Form 10-K for year ended December 31, 2015, filed on February 17, 2016
†	(xl)	Form of Award Letter for Anadarko Petroleum Corporation 2008 Director Compensation Plan, filed as Exhibit 10.3 to Form 8-K filed on May 27, 2008
†	(xli)	Form of Award Letter for Anadarko Petroleum Corporation 2008 Director Compensation Plan (2013), filed as Exhibit 10(i) to Form 10-Q for quarter ended June 30, 2013, filed on July 29, 2013
†	(xlii)	Form of Award Letter for Anadarko Petroleum Corporation 2008 Director Compensation Plan Annual Deferred Shares (2016), filed as Exhibit 10(iii) to Form 10-Q for quarter ended March 31, 2016, filed on May 2, 2016
†	(xliii)	Terms and Conditions of Elective Deferred Share Awards for Anadarko Petroleum Corporation 2008 Director Compensation Plan, filed as Exhibit 10(iv) to Form 10-Q for quarter ended March 31, 2016, filed on May 2, 2016
†	(xliv)	Anadarko Petroleum Corporation Deferred Compensation Plan (as amended and restated effective as of January 1, 2012), filed as Exhibit 10(i) to Form 10-Q for quarter ended June 30, 2014, filed on July 29, 2014
†	(xlv)	First Amendment, dated December 17, 2013, to the Anadarko Petroleum Corporation Deferred Compensation Plan (as amended and restated effective as of January 1, 2012), filed as Exhibit 10(ii) to Form 10-Q for quarter ended June 30, 2014, filed on July 29, 2014
	(xlvi)	Operating Agreement, dated October 1, 2009, between BP Exploration & Production Inc., as Operator, and MOEX Offshore 2007 LLC, as Non-Operator, as ratified by that certain Ratification and Joinder of Operating Agreement, dated December 17, 2009, by and among BP Exploration & Production Inc., Anadarko Petroleum Corporation (as Non-Operator), Anadarko E&P Company LP (as predecessor in interest to Anadarko Petroleum Corporation), and MOEX Offshore 2007 LLC, together with material exhibits, filed as Exhibit 10 to Form 10-Q for quarter ended June 30, 2010, filed on August 3, 2010

	Exhibit Number	Description
	10 (xlvii)	Confidential Settlement Agreement, Mutual Releases and Agreement to Indemnify, dated October 16, 2011, by and among BP Exploration & Production Inc., Anadarko Petroleum Corporation, Anadarko E&P Company LP, BP Corporation North America Inc. and BP p.l.c., filed as Exhibit 10(xlii) to Form 10-K for year ended December 31, 2011, filed on February 21, 2012 (Portions of this exhibit have been omitted and filed separately with the SEC pursuant to a request for confidential treatment)
†	(xlviii)	Severance Agreement between R. A. Walker and Anadarko Petroleum Corporation, dated February 16, 2012, filed as Exhibit 10.2 to Form 8-K filed on February 21, 2012
†	(xlix)	Time Sharing Agreement between R. A. Walker and Anadarko Petroleum Corporation, dated May 15, 2012, filed as Exhibit 10(ii) to Form 10-Q for quarter ended June 30, 2012, filed on August 8, 2012
†	(l)	First Amendment to Time Sharing Agreement between R. A. Walker and Anadarko Petroleum Corporation, dated June 2, 2015, filed as Exhibit 10(ii) to Form 10-Q for quarter ended June 30, 2015, filed on July 28, 2015
†	(li)	Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan, effective as of May 15, 2012, filed as Exhibit 10.1 to Form 8-K filed on May 15, 2012
†	(lii)	Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan, as Amended and Restated Effective as of May 10, 2016, filed as Exhibit 10.1 to Form 8-K filed on May 16, 2016
†	(liii)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan Stock Option Award Agreement, filed as Exhibit 10.2 to Form 8-K filed on May 15, 2012
†	(liv)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan Restricted Stock Unit Award Agreement, filed as Exhibit 10.3 to Form 8-K filed on May 15, 2012
†	(lv)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan Performance Unit Award Agreement, filed as Exhibit 10.4 to Form 8-K filed on May 15, 2012
†	(lvi)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan Restricted Stock Unit Award Agreement, filed as Exhibit 10.1 to Form 8-K filed on November 9, 2012
†	(lvii)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan Performance Unit Award Agreement, filed as Exhibit 10.2 to Form 8-K filed on November 9, 2012
†	(lviii)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan Performance Unit Award Agreement (2014), filed as Exhibit 10.1 to Form 8-K filed on November 10, 2014
†	(lix)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan, as Amended and Restated Effective as of May 10, 2016, Stock Option Award Agreement, filed as Exhibit 10(i) to Form 10-Q for quarter ended September 30, 2016, filed on October 31, 2016
†	(lx)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan, as Amended and Restated Effective as of May 10, 2016, Restricted Stock Unit Award Agreement, filed as Exhibit 10(ii) to Form 10-Q for quarter ended September 30, 2016, filed on October 31, 2016
†	(lxi)	Form of Anadarko Petroleum Corporation 2012 Omnibus Incentive Compensation Plan, as Amended and Restated Effective as of May 10, 2016, Performance Unit Award Agreement, filed as Exhibit 10(iii) to Form 10-Q for quarter ended September 30, 2016, filed on October 31, 2016
†	(lxii)	Form of U.K. Award Letter for Anadarko Petroleum Corporation 2008 Director Compensation Plan, filed as Exhibit 10.5 to Form 8-K filed on May 15, 2012
†	(lxiii)	Amended and Restated Performance Unit Award Agreement, effective November 5, 2012, for R. A. Walker, filed as Exhibit 10.3 to Form 8-K filed on November 9, 2012

	Exhibit Number		Description
	10	(lxiv)	Settlement Agreement dated as of April 3, 2014, by and among (1) the Anadarko Litigation Trust, (2) the United States of America in its capacity as plaintiff-intervenor in the Tronox Adversary Proceeding and acting for and on behalf of certain U.S. government agencies and (3) Anadarko Petroleum Corporation, Kerr-McGee Corporation, and certain other subsidiaries, filed as Exhibit 10.1 to Form 8-K filed on April 3, 2014
		(lxv)	Credit Agreement, dated as of June 17, 2014, among Anadarko Petroleum Corporation, as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, Wells Fargo Bank, National Association, as Syndication Agent, Bank of America, N.A., Citibank, N.A., The Royal Bank of Scotland plc, and The Bank of Tokyo-Mitsubishi UFJ, Ltd., as Co-Documentation Agents, and the additional lenders party thereto, filed as Exhibit 10.1 to Form 8-K filed on June 23, 2014
		(lxvi)	First Amendment to Credit Agreement, dated November 14, 2014, among Anadarko Petroleum Corporation, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto, filed as Exhibit 10.1 to Form 8-K filed on November 19, 2014
		(lxvii)	Amendment and Maturity Extension Agreement, dated December 14, 2015, among Anadarko Petroleum Corporation, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto, filed as Exhibit 10.1 to Form 8-K filed on December 18, 2015
		(lxviii)	Form of Commercial Paper Dealer Agreement for Commercial Paper Program, filed as Exhibit 10.1 to Form 8-K filed on January 21, 2015
†		(lxix)	Anadarko Petroleum Corporation Key Employee Change of Control Contract, dated June 1, 2015, for Christopher O. Champion, filed as Exhibit 10(i) to Form 10-Q for quarter ended June 30, 2015, filed on July 28, 2015
		(lxx)	364-Day Revolving Credit Agreement, dated as of January 19, 2016, among Anadarko Petroleum Corporation, as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, Wells Fargo Bank, National Association, as Syndication Agent, Bank of America, N.A., The Bank of Tokyo-Mitsubishi UFJ, Ltd., Citibank, N.A., and Mizuho Bank, Ltd., as Co-Documentation Agents, and the additional lenders party thereto, filed as Exhibit 10.1 to Form 8-K filed on January 25, 2016
		(lxxi)	First Amendment to 364-Day Revolving Credit Agreement, dated January 13, 2017, among Anadarko Petroleum Corporation, JPMorgan Chase Bank, N.A., as administrative agent, and the additional lenders party thereto, filed as Exhibit 10.1 to Form 8-K filed on January 20, 2017
†*		(lxxii)	Retention Agreement, dated as of November 1, 2015, between Anadarko Petroleum Corporation and Mitchell W. Ingram
†*		(lxxiii)	First Amendment to Retention Agreement, dated December 13, 2016
*	12		Computation of Ratios of Earnings to Fixed Charges
*	21		List of Subsidiaries
*	23	(i)	Consent of KPMG LLP
*	23	(ii)	Consent of Miller and Lents, Ltd.
*	24		Power of Attorney
*	31	(i)	Rule 13a-14(a)/15d-14(a) Certification—Chief Executive Officer
*	31	(ii)	Rule 13a-14(a)/15d-14(a) Certification—Chief Financial Officer
**	32		Section 1350 Certifications
*	99		Report of Miller and Lents, Ltd.
*	101	.INS	XBRL Instance Document
*	101	.SCH	XBRL Schema Document
*	101	.CAL	XBRL Calculation Linkbase Document
*	101	.DEF	XBRL Definition Linkbase Document
*	101	.LAB	XBRL Label Linkbase Document
*	101	.PRE	XBRL Presentation Linkbase Document

† Management contracts or compensatory plans or arrangements required to be filed pursuant to Item 15.

The total amount of securities of the registrant authorized under any instrument with respect to long-term debt not filed as an exhibit does not exceed 10% of the total assets of the registrants and its subsidiaries on a consolidated basis. The registrant agrees, upon request of the SEC, to furnish copies of any or all of such instruments to the SEC.

b) FINANCIAL STATEMENT SCHEDULES

Financial statement schedules have been omitted because they are not required, not applicable, or the information is included in the Company's Consolidated Financial Statements.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ANADARKO PETROLEUM CORPORATION

February 17, 2017 By: /s/ ROBERT G. GWIN

Robert G. Gwin
Executive Vice President, Finance and Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on February 17, 2017.

Name and Signature	Title
(i) Principal executive officer and director:	
/s/ R. A. WALKER R. A. Walker	Chairman, President and Chief Executive Officer
(ii) Principal financial officer:	
/s/ ROBERT G. GWIN Robert G. Gwin	Executive Vice President, Finance and Chief Financial Officer
(iii) Principal accounting officer:	
/s/ CHRISTOPHER O. CHAMPION Christopher O. Champion	Senior Vice President, Chief Accounting Officer and Controller

(iv) Directors:*

ANTHONY R. CHASE
KEVIN P. CHILTON
DAVID E. CONSTABLE
H. PAULETT EBERHART
CLAIRE S. FARLEY
PETER J. FLUOR
RICHARD L. GEORGE
JOSEPH W. GORDER
JOHN R. GORDON
SEAN GOURLEY
MARK C. MCKINLEY
ERIC D. MULLINS

* Signed on behalf of each of these persons and on his own behalf:

By: /s/ ROBERT G. GWIN
Robert G. Gwin, Attorney-in-Fact

Exhibit 118

Company:	ANADARKO PETROLEUM CORP
Document:	10-Q • 05/02/2017
	10-Q •
Section:	Entire Document
File Number:	001-08968
Pages:	0

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549

FORM 10-Q

(Mark One)

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2017

or

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from to

Commission File No. 1-8968

ANADARKO PETROLEUM CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	**76-0146568**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1201 Lake Robbins Drive, The Woodlands, Texas	**77380-1046**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code **(832) 636-1000**

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐ Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The number of shares outstanding of the Company's common stock at April 19, 2017, is shown below:

Title of Class	Number of Shares Outstanding
Common Stock, par value $0.10 per share	560,339,140

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COMMONLY USED TERMS AND DEFINITIONS

Unless the context otherwise requires, the terms "Anadarko" and "Company" refer to Anadarko Petroleum Corporation and its consolidated subsidiaries. In addition, the following company or industry-specific terms and abbreviations are used throughout this report:

364-Day Facility - Anadarko's $2.0 billion 364-day senior unsecured RCF maturing in January 2018
ASU - Accounting Standards Update
Bcf - Billion cubic feet
BOE - Barrels of oil equivalent
DBJV - Delaware Basin JV Gathering LLC
DBJV system - A gathering system and related facilities located in the Delaware basin in Loving, Ward, Winkler, and Reeves Counties in West Texas
DBM complex - The processing plants, gas gathering system, and related facilities and equipment in West Texas that serve production from Reeves, Loving and Culberson Counties, Texas and Eddy and Lea Counties, New Mexico
DD&A - Depreciation, depletion, and amortization
EPA - U.S. Environmental Protection Agency
Five-Year Facility - Anadarko's $3.0 billion five-year senior unsecured RCF maturing in January 2021
FPSO - Floating production, storage, and offloading unit
G&A - General and administrative expenses
GAAP - U.S. Generally Accepted Accounting Principles
GOM Acquisition - Acquisition of oil and natural-gas assets in the Gulf of Mexico, which closed on December 15, 2016
IPO - Initial public offering
LIBOR - London Interbank Offered Rate
LNG - Liquefied natural gas
MBbls/d - Thousand barrels per day
MBOE/d - Thousand barrels of oil equivalent per day
Mcf - Thousand cubic feet
MMBbls - Million barrels
MMBOE - Million barrels of oil equivalent
MMBtu - Million British thermal units
MMBtu/d - Million British thermal units per day
MMcf/d - Million cubic feet per day
Moody's - Moody's Investors Service
NGLs - Natural gas liquids
NM - Not meaningful
NYMEX - New York Mercantile Exchange
Oil - Includes crude oil and condensate
OPEC - Organization of the Petroleum Exporting Countries
RCF - Revolving credit facility
S&P - Standard and Poor's
TEN - Tweneboa/Enyenra/Ntomme
TEU or TEUs - Tangible equity units
VIE - Variable interest entity
WES - Western Gas Partners, LP, a limited partnership and publicly-traded consolidated subsidiary of Anadarko
WES RCF - WES's $1.2 billion five-year senior unsecured RCF maturing in February 2020
WGP - Western Gas Equity Partners, LP, a limited partnership and publicly-traded consolidated subsidiary of Anadarko
WGP RCF - WGP's $250 million three-year senior secured RCF maturing in March 2019
Zero Coupons - Anadarko's Zero-Coupon Senior Notes due 2036

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

millions except per-share amounts	Three Months Ended March 31, 2017	2016
Revenues and Other		
Oil sales	**$ 1,663**	$ 850
Natural-gas sales	**502**	366
Natural-gas liquids sales	**289**	178
Gathering, processing, and marketing sales	**444**	240
Gains (losses) on divestitures and other, net	**869**	40
Total	**3,767**	1,674
Costs and Expenses		
Oil and gas operating	**258**	208
Oil and gas transportation	**249**	242
Exploration	**1,085**	126
Gathering, processing, and marketing	**351**	215
General and administrative	**269**	449
Depreciation, depletion, and amortization	**1,115**	1,149
Production, property, and other taxes	**155**	117
Impairments	**373**	16
Other operating expense	**22**	16
Total	**3,877**	2,538
Operating Income (Loss)	**(110)**	(864)
Other (Income) Expense		
Interest expense	**223**	220
(Gains) losses on derivatives, net	**(147)**	297
Other (income) expense, net	**(8)**	—
Total	**68**	517
Income (Loss) Before Income Taxes	**(178)**	(1,381)
Income tax expense (benefit)	**97**	(383)
Net Income (Loss)	**(275)**	(998)
Net income (loss) attributable to noncontrolling interests	**43**	36
Net Income (Loss) Attributable to Common Stockholders	**$ (318)**	$ (1,034)
Per Common Share		
Net income (loss) attributable to common stockholders—basic	**$ (0.58)**	$ (2.03)
Net income (loss) attributable to common stockholders—diluted	**$ (0.58)**	$ (2.03)
Average Number of Common Shares Outstanding—Basic	**551**	509
Average Number of Common Shares Outstanding—Diluted	**551**	509
Dividends (per Common Share)	**$ 0.05**	$ 0.05

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

millions	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
Net Income (Loss)	**$ (275)**	$ (998)
Other Comprehensive Income (Loss)		
Adjustments for derivative instruments		
Reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	**1**	3
Income taxes on reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	**—**	(1)
Total adjustments for derivative instruments, net of taxes	**1**	2
Adjustments for pension and other postretirement plans		
Net gain (loss) incurred during period	**(4)**	(166)
Income taxes on net gain (loss) incurred during period	**1**	61
Prior service credit (cost) incurred during period	**—**	(1)
Income taxes on prior service credit (cost) incurred during period	**—**	1
Amortization of net actuarial (gain) loss to general and administrative expense	**9**	8
Income taxes on amortization of net actuarial (gain) loss to general and administrative expense	**(3)**	(3)
Amortization of net prior service (credit) cost to general and administrative expense	**(6)**	(15)
Income taxes on amortization of net prior service (credit) cost to general and administrative expense	**2**	5
Total adjustments for pension and other postretirement plans, net of taxes	**(1)**	(110)
Total	**—**	(108)
Comprehensive Income (Loss)	**(275)**	(1,106)
Comprehensive income (loss) attributable to noncontrolling interests	**43**	36
Comprehensive Income (Loss) Attributable to Common Stockholders	**$ (318)**	$ (1,142)

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED BALANCE SHEETS
(Unaudited)

millions	**March 31, 2017**	December 31, 2016
ASSETS		
Current Assets		
Cash and cash equivalents ($123 and $359 related to VIEs)	**$ 5,831**	$ 3,184
Accounts receivable (net of allowance of $16 and $14)		
Customers ($81 and $70 related to VIEs)	**973**	1,007
Others ($12 and $80 related to VIEs)	**604**	721
Other current assets	**299**	354
Total	**7,707**	5,266
Properties and Equipment		
Cost	**64,485**	69,013
Less accumulated depreciation, depletion, and amortization	**35,420**	36,845
Net properties and equipment ($5,264 and $5,050 related to VIEs)	**29,065**	32,168
Other Assets ($608 and $609 related to VIEs)	**2,182**	2,226
Goodwill and Other Intangible Assets ($1,214 and $1,221 related to VIEs)	**5,739**	5,904
Total Assets	**$ 44,693**	$ 45,564
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable		
Trade ($166 and $234 related to VIEs)	**$ 1,637**	$ 1,617
Other	**342**	303
Short-term debt	**42**	42
Current asset retirement obligations	**258**	129
Other current liabilities	**1,483**	1,237
Total	**3,762**	3,328
Long-term Debt	**15,284**	15,281
Other Long-term Liabilities		
Deferred income taxes	**3,664**	4,324
Asset retirement obligations ($142 and $140 related to VIEs)	**2,684**	2,802
Other	**4,220**	4,332
Total	**10,568**	11,458
Equity		
Stockholders' equity		
Common stock, par value $0.10 per share (1.0 billion shares authorized, 573.0 million and 572.0 million shares issued)	**57**	57
Paid-in capital	**11,914**	11,875
Retained earnings	**1,330**	1,704
Treasury stock (21.1 million and 20.8 million shares)	**(1,054)**	(1,033)
Accumulated other comprehensive income (loss)	**(391)**	(391)
Total Stockholders' Equity	**11,856**	12,212
Noncontrolling interests	**3,223**	3,285
Total Equity	**15,079**	15,497
Total Liabilities and Equity	**$ 44,693**	$ 45,564

Parenthetical references reflect amounts as of March 31, 2017, and December 31, 2016.

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENT OF EQUITY
(Unaudited)

	Total Stockholders' Equity						
millions	Common Stock	Paid-in Capital	Retained Earnings	Treasury Stock	Accumulated Other Comprehensive Income (Loss)	Non-controlling Interests	Total Equity
Balance at December 31, 2016	$ 57	$11,875	$ 1,704	$ (1,033)	$ (391)	$ 3,285	$ 15,497
Net income (loss)	—	—	(318)	—	—	43	(275)
Common stock issued [(1)]	—	42	—	—	—	—	42
Dividends—common stock	—	—	(28)	—	—	—	(28)
Repurchase of common stock	—	—	—	(21)	—	—	(21)
Distributions to noncontrolling interest owners	—	—	—	—	—	(105)	(105)
Reclassification of previously deferred derivative losses to (gains) losses on derivatives, net	—	—	—	—	1	—	1
Adjustments for pension and other postretirement plans	—	—	—	—	(1)	—	(1)
Cumulative effect of accounting change	—	(3)	(28)	—	—	—	(31)
Balance at March 31, 2017	$ 57	$11,914	$ 1,330	$ (1,054)	$ (391)	$ 3,223	$ 15,079

(1) Represents share-based compensation expense.

See accompanying Notes to Consolidated Financial Statements.

ANADARKO PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

millions	Three Months Ended March 31, 2017	2016
Cash Flows from Operating Activities		
Net income (loss)	$ **(275)**	$ (998)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities		
Depreciation, depletion, and amortization	**1,115**	1,149
Deferred income taxes	**(660)**	(413)
Dry hole expense and impairments of unproved properties	**1,012**	35
Impairments	**373**	16
(Gains) losses on divestitures, net	**(804)**	(2)
Total (gains) losses on derivatives, net	**(147)**	299
Operating portion of net cash received (paid) in settlement of derivative instruments	**(8)**	105
Other	**83**	115
Changes in assets and liabilities		
(Increase) decrease in accounts receivable	**68**	46
Increase (decrease) in accounts payable and other current liabilities	**395**	(326)
Other items, net	**(29)**	(163)
Net cash provided by (used in) operating activities	**1,123**	(137)
Cash Flows from Investing Activities		
Additions to properties and equipment	**(1,194)**	(1,022)
Divestitures of properties and equipment and other assets	**2,851**	35
Other, net	**65**	14
Net cash provided by (used in) investing activities	**1,722**	(973)
Cash Flows from Financing Activities		
Borrowings, net of issuance costs	**—**	4,682
Repayments of debt	**(10)**	(1,608)
Financing portion of net cash received (paid) for derivative instruments	**(37)**	(555)
Increase (decrease) in outstanding checks	**28**	(150)
Dividends paid	**(28)**	(25)
Repurchase of common stock	**(21)**	(30)
Issuance of common stock	**—**	30
Sale of subsidiary units	**—**	440
Distributions to noncontrolling interest owners	**(105)**	(78)
Proceeds from conveyance of future hard minerals royalty revenues, net of transaction costs	**—**	413
Payments of future hard minerals royalty revenues conveyed	**(25)**	—
Net cash provided by (used in) financing activities	**(198)**	3,119
Effect of Exchange Rate Changes on Cash	**—**	(1)
Net Increase (Decrease) in Cash and Cash Equivalents	**2,647**	2,008
Cash and Cash Equivalents at Beginning of Period	**3,184**	939
Cash and Cash Equivalents at End of Period	$ **5,831**	$ 2,947

See accompanying Notes to Consolidated Financial Statements.

1. Summary of Significant Accounting Policies

General Anadarko Petroleum Corporation is engaged in the exploration, development, production, and marketing of oil, natural gas, and NGLs and in the marketing of anticipated production of LNG. In addition, the Company engages in the gathering, processing, treating, and transporting of oil, natural gas, and NGLs as well as gathering and disposal of produced water. The Company also participates in the hard-minerals business through royalty arrangements.

Basis of Presentation The accompanying unaudited consolidated financial statements have been prepared in accordance with GAAP for interim financial information and the instructions to Form 10-Q and Article 10 of Regulation S-X. Accordingly, certain notes and other information have been condensed or omitted. The accompanying interim financial statements reflect all normal recurring adjustments that are, in the opinion of management, necessary for the fair presentation of the Company's consolidated financial statements. Certain prior-period amounts have been reclassified to conform to the current-period presentation. These interim financial statements should be read in conjunction with the consolidated financial statements and accompanying notes included in the Company's Annual Report on Form 10-K for the year ended December 31, 2016.

The consolidated financial statements include the accounts of Anadarko and subsidiaries in which Anadarko holds, directly or indirectly, more than 50% of the voting rights and VIEs for which Anadarko is the primary beneficiary. All intercompany transactions have been eliminated. Undivided interests in oil and natural-gas exploration and production joint ventures are consolidated on a proportionate basis. Investments in noncontrolled entities over which Anadarko has the ability to exercise significant influence over operating and financial policies and VIEs for which Anadarko is not the primary beneficiary are accounted for using the equity method. In applying the equity method of accounting, the investments are initially recognized at cost and subsequently adjusted for the Company's proportionate share of earnings, losses, and distributions. Other investments are carried at original cost. Investments accounted for using the equity method and cost method are included in other assets.

Recently Adopted Accounting Standards ASU 2017-01, *Business Combinations (Topic 805): Clarifying the Definition of a Business,* assists in determining whether a transaction should be accounted for as an acquisition or disposal of assets or as a business. This ASU provides a screen that when substantially all of the fair value of the gross assets acquired, or disposed of, are concentrated in a single identifiable asset, or a group of similar identifiable assets, the set will not be considered a business. If the screen is not met, a set must include an input and a substantive process that together significantly contribute to the ability to create an output to be considered a business. The Company's adoption of this ASU on January 1, 2017, using a prospective approach, could have a material impact on consolidated financial statements as goodwill will not be allocated to divestitures or recorded on acquisitions that are not considered to be a business. The Company's disposition of Eagleford oil and gas properties in the first quarter of 2017 was not considered a business under this ASU and therefore not allocated goodwill, see *Note 3—Acquisitions, Divestitures, and Assets Held for Sale*.

ASU 2016-16, *Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other Than Inventory,* requires an entity to recognize the income tax consequences of an intra-entity transfer of an asset other than inventory when the transfer occurs and eliminates the exception for an intra-entity transfer of an asset other than inventory. The Company adopted this ASU on January 1, 2017, using a modified retrospective approach, and recognized a cumulative adjustment to retained earnings of $31 million during the first quarter of 2017.

1. Summary of Significant Accounting Policies (Continued)

ASU 2016-09, *Compensation—Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting,* simplifies the accounting for share-based payment transactions, including the income tax consequences, classification on the statement of cash flows, accounting for forfeitures, and classification of awards as either equity or liabilities. The Company adopted this ASU on January 1, 2017. As a result of adoption, share-based compensation excess tax benefits and tax deficiencies are reflected on a prospective basis in the income statement as a component of the provision for income taxes rather than additional paid-in capital as previously recognized. For the three months ended March 31, 2017, the Company recognized a $15 million tax deficiency as an increase to the provision for income taxes. Cash flows related to excess tax benefits have been classified on a prospective basis as operating activities in the statement of cash flows rather than cash inflows from financing activities and cash outflows from operating activities as previously recognized. Prior periods of the statement of cash flows were not adjusted as there was no material impact. In addition, the Company elected to begin accounting for share-based compensation award forfeitures when they occur instead of estimating the number of forfeitures expected. This change in accounting policy for share-based compensation award forfeitures did not have a material impact on the Company's consolidated financial statements.

New Accounting Standards Issued But Not Yet Adopted ASU 2017-07, *Compensation—Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost,* requires presentation of service cost in the same line item(s) as other compensation costs arising from services rendered by employees during the period and presentation of the remaining components of net benefit cost in a separate line item outside operating items. Additionally, only the service cost component of net benefit cost will be eligible for capitalization. The Company will adopt this ASU on January 1, 2018, with retrospective presentation of the service cost component and the other components of net benefit cost in the income statement and prospective presentation for the capitalization of the service cost component of net benefit cost in assets. The Company is evaluating the impact of the adoption of this ASU on its consolidated financial statements.

ASU 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash,* requires an entity to explain the changes in the total of cash, cash equivalents, restricted cash, and restricted cash equivalents on the statement of cash flows and to provide a reconciliation of the totals in that statement to the related captions in the balance sheet when the cash, cash equivalents, restricted cash, and restricted cash equivalents are presented in more than one line item on the balance sheet. This ASU is effective for annual and interim periods beginning after December 15, 2017, and is required to be adopted using a retrospective approach, with early adoption permitted. The Company is evaluating the impact of the adoption of this ASU on its consolidated financial statements.

ASU 2016-15, *Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments,* provides clarification on how certain cash receipts and cash payments are presented and classified on the statement of cash flows. This ASU is effective for annual and interim periods beginning after December 15, 2017, and is required to be adopted using a retrospective approach if practicable, with early adoption permitted. The Company does not expect the adoption of this ASU to have a material impact on its Consolidated Statement of Cash Flows.

ANADARKO PETROLEUM CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Summary of Significant Accounting Policies (Continued)

ASU 2014-09, *Revenue from Contracts with Customers (Topic 606),* supersedes current revenue recognition requirements and industry-specific guidance. The codification requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services. Additional disclosures will be required to describe the nature, amount, timing, and uncertainty of revenue and cash flows from contracts with customers. The Company has completed an initial review of contracts in each of its revenue streams and is developing accounting policies to address the provisions of the ASU. While the Company does not currently expect net earnings to be materially impacted, the Company is currently analyzing whether total revenues and total expenses may increase as a result of recognizing both revenue for noncash consideration for services provided by our midstream business and revenue and associated cost of product for the subsequent sale of commodities received as such noncash consideration. Anadarko continues to evaluate the impact of this and other provisions of the ASU on its accounting policies, internal controls, and consolidated financial statements and related disclosures and has not finalized any estimates of the potential impacts. The Company will adopt the new standard on January 1, 2018, using the modified retrospective method with a cumulative adjustment to retained earnings.

ASU 2016-02, *Leases (Topic 842),* requires lessees to recognize a lease liability and a right-of-use asset for all leases, including operating leases, with a term greater than 12 months on the balance sheet. The provisions of ASU 2016-02 also modify the definition of a lease and outline the requirements for recognition, measurement, presentation, and disclosure of leasing arrangements by both lessees and lessors. This ASU is effective for annual and interim periods beginning after December 15, 2018. The Company is currently analyzing its portfolio of contracts to assess the impact future adoption of this ASU may have on its consolidated financial statements.

2. Inventories

The following summarizes the major classes of inventories included in other current assets:

millions	**March 31, 2017**	December 31, 2016
Oil	**$ 130**	$ 169
Natural gas	**19**	38
NGLs	**94**	106
Total inventories	**$ 243**	$ 313

3. Acquisitions, Divestitures, and Assets Held for Sale

Acquisition On December 15, 2016, the Company closed the GOM Acquisition for $1.8 billion using a portion of the net proceeds from the September 2016 issuance of 40.5 million shares of its common stock. The GOM Acquisition constitutes a business combination and was accounted for using the acquisition method of accounting. The fair-value measurements of the assets acquired and liabilities assumed at the acquisition date were still preliminary as of March 31, 2017, pending customary closing adjustments. There were no material changes to the fair value of the assets acquired and liabilities assumed from the amounts included on the Company's Consolidated Balance Sheet at December 31, 2016.

Property Exchange On March 17, 2017, WES acquired a third party's 50% nonoperated interest in the DBJV system in exchange for WES's 33.75% interest in nonoperated Marcellus midstream assets and $155 million in cash. WES funded the cash consideration with cash on hand and recognized a gain of $125 million as a result of this transaction. After the acquisition, the DBJV system is 100% owned by WES and consolidated by Anadarko.

Divestitures and Assets Held for Sale The following summarizes the proceeds received and gains (losses) recognized on divestitures and assets held for sale for the three months ended March 31:

millions	**2017**	2016
Proceeds received, net of closing adjustments	**$ 2,851**	$ 35
Gains (losses) on divestitures, net	**804**	2

During the three months ended March 31, 2017, the Company divested certain U.S. onshore assets located in the Eagleford area of South Texas for net proceeds of $2.1 billion and a net gain of $726 million. These assets were included in the oil and gas exploration and production reporting segment.

Certain Marcellus U.S. onshore assets located in Pennsylvania included in the oil and gas exploration and production and midstream reporting segments satisfied criteria to be considered held for sale during the fourth quarter of 2016, at which time the Company remeasured these assets to their current fair value using a market approach and Level 2 fair-value inputs and recognized a loss of $129 million. The sale of these assets closed during the first quarter of 2017 for net proceeds of $763 million and an additional loss of $44 million. Remaining proceeds of $196 million are currently held in escrow by the purchaser, pending regulatory approval. At March 31, 2017, the Company's Consolidated Balance Sheet included long-term assets of $215 million, which includes $35 million of goodwill, and long-term liabilities of $15 million, primarily associated with Marcellus assets held in escrow subject to regulatory approval.

4. Impairments

Impairments of Long-Lived Assets Impairments of long-lived assets are included in impairment expense in the Company's Consolidated Statements of Income. The following summarizes impairments of long-lived assets and the related post-impairment fair values by segment:

	Three Months Ended	
millions	Impairment	Fair Value [1]
March 31, 2017		
Oil and gas exploration and production		
Gulf of Mexico properties	$ 204	$ 231
Midstream	169	49
Total	$ 373	$ 280

[1] Measured as of the impairment date using the income approach and Level 3 inputs. The primary assumptions used to estimate undiscounted future net cash flows include anticipated future production, commodity prices, and capital and operating costs.

Impairments during the three months ended March 31, 2017, were primarily related to oil and gas properties in the Gulf of Mexico due to lower forecasted commodity prices and a U.S. onshore midstream property due to a reduced throughput fee as a result of a producer's bankruptcy.

Impairments of Unproved Properties Impairments of unproved properties are included in exploration expense in the Company's Consolidated Statements of Income. The Company recognized $532 million of impairments of unproved Gulf of Mexico properties during the three months ended March 31, 2017, of which $467 million related to the Shenandoah project. The unproved property balance related to the Shenandoah project originated from the purchase price allocated to Gulf of Mexico exploration projects from the acquisition of Kerr-McGee Corporation in 2006. For additional details on the Shenandoah project, see *Note 5—Suspended Exploratory Well Costs*.

Potential for Future Impairments

Oil price sensitivity At March 31, 2017, the Company's estimate of undiscounted future cash flows attributable to certain asset groups, primarily related to international and offshore properties, with a combined net book value of approximately $2.7 billion indicated that the carrying amounts were expected to be recovered; however, these asset groups may be at risk for impairment if the estimates of future cash flows decline. The Company estimates that a 10% decline in oil prices (with all other assumptions unchanged) could result in non-cash impairments in excess of $1.0 billion.

Natural-gas price sensitivity At March 31, 2017, the Company's estimate of undiscounted future cash flows attributable to certain U.S. onshore asset groups with a combined net book value of approximately $1.3 billion indicated that the carrying amounts were expected to be recovered; however, these asset groups may be at risk for impairment if the estimates of future cash flows decline. The Company estimates that a 10% decline in natural-gas prices (with all other assumptions unchanged) could result in non-cash impairments in excess of $500 million.

It is also reasonably possible that significant declines in commodity prices, further changes to the Company's drilling plans in response to lower prices, reduction of proved and probable reserve estimates, or increases in drilling or operating costs could result in other additional impairments.

5. Suspended Exploratory Well Costs

The Company's suspended exploratory well costs were $1.1 billion at March 31, 2017, and $1.2 billion at December 31, 2016. Projects with suspended exploratory well costs include wells that have sufficient reserves to justify completion as a producing well and sufficient progress is being made in assessing the reserves and the economic and operating viability of the project. If additional information becomes available that raises substantial doubt as to the economic or operational viability of any of these projects, the associated costs will be expensed at that time.

During the three months ended March 31, 2017, the Company expensed suspended exploratory well costs of $435 million related to the Shenandoah project in the Gulf of Mexico, including $267 million previously capitalized for a period greater than one year. The Shenandoah-6 appraisal well and subsequent sidetrack, which completed appraisal activities in April 2017, did not encounter the oil-water contact in the eastern portion of the field. Given the results of this well and the present commodity-price environment, the Company has currently suspended further appraisal activities. Accordingly, the Company determined that the Shenandoah project no longer satisfies the accounting requirements for the continued capitalization of the exploratory well costs.

6. Current Liabilities

Accounts Payable Accounts payable, trade included liabilities of $290 million at March 31, 2017, and $262 million at December 31, 2016, representing the amount by which checks issued but not presented to the Company's banks for collection exceeded balances in applicable bank accounts. Changes in these liabilities are classified as cash flows from financing activities.

Other Current Liabilities The following summarizes the Company's other current liabilities:

millions	**March 31, 2017**	December 31, 2016
Accrued income taxes	**$ 671**	$ 6
Interest payable	**161**	244
Production, property, and other taxes payable	**253**	239
Accrued employee benefits	**185**	355
Other	**213**	393
Total other current liabilities	**$ 1,483**	$ 1,237

7. Derivative Instruments

Objective and Strategy The Company uses derivative instruments to manage its exposure to cash-flow variability from commodity-price and interest-rate risks. Futures, swaps, and options are used to manage exposure to commodity-price risk inherent in the Company's oil and natural-gas production and natural-gas processing operations (Oil and Natural-Gas Production/Processing Derivative Activities). Futures contracts and commodity-price swap agreements are used to fix the price of expected future oil and natural-gas sales at major industry trading locations such as Cushing, Oklahoma or Sullom Voe, Scotland for oil and Henry Hub, Louisiana for natural gas. Basis swaps are periodically used to fix or float the price differential between product prices at one market location versus another. Options are used to establish a floor price, a ceiling price, or a floor and a ceiling price (collar) for expected future oil and natural-gas sales. Derivative instruments are also used to manage commodity-price risk inherent in customer price requirements and to fix margins on the future sale of natural gas and NGLs from the Company's leased storage facilities (Marketing and Trading Derivative Activities).

Interest-rate swaps are used to fix or float interest rates on existing or anticipated indebtedness. The purpose of these instruments is to manage the Company's existing or anticipated exposure to interest-rate changes. The fair value of the Company's current interest-rate swap portfolio is subject to changes in interest rates.

The Company does not apply hedge accounting to any of its derivative instruments. As a result, gains and losses associated with derivative instruments are recognized currently in earnings. Net derivative losses attributable to derivatives previously subject to hedge accounting reside in accumulated other comprehensive income (loss) and are reclassified to earnings as the transactions to which the derivatives relate are recognized in earnings.

Oil and Natural-Gas Production/Processing Derivative Activities The oil prices listed below are a combination of NYMEX West Texas Intermediate and Intercontinental Exchange, Inc. (ICE) Brent Blend prices. The natural-gas prices listed below are NYMEX Henry Hub prices. The NGLs prices listed below are Oil Price Information Services prices. The following is a summary of the Company's derivative instruments related to oil and natural-gas production/processing derivative activities at March 31, 2017:

	2017 Settlement	2018 Settlement
Oil		
Three-Way Collars (MBbls/d)	91	—
Average price per barrel		
Ceiling sold price (call)	$ 59.80	$ —
Floor purchased price (put)	$ 50.00	$ —
Floor sold price (put)	$ 40.00	$ —
Natural Gas		
Three-Way Collars (thousand MMBtu/d)	682	250
Average price per MMBtu		
Ceiling sold price (call)	$ 3.60	$ 3.54
Floor purchased price (put)	$ 2.75	$ 2.75
Floor sold price (put)	$ 2.00	$ 2.00
Fixed-Price Contracts (thousand MMBtu/d)	19	—
Average price per MMBtu	$ 2.82	$ —

A three-way collar is a combination of three options: a sold call, a purchased put, and a sold put. The sold call establishes the maximum price that the Company will receive for the contracted commodity volumes. The purchased put establishes the minimum price that the Company will receive for the contracted volumes unless the market price for the commodity falls below the sold put strike price, at which point the minimum price equals the reference price (e.g., NYMEX) plus the excess of the purchased put strike price over the sold put strike price.

7. Derivative Instruments (Continued)

Marketing and Trading Derivative Activities The Company had financial derivative transactions with notional volumes of natural gas totaling 2 Bcf at March 31, 2017, and December 31, 2016, that were entered into to mitigate commodity-price risk related to fixed-price purchase and sales contracts and storage activity.

Interest-Rate Derivatives Anadarko has outstanding interest-rate swap contracts to manage interest-rate risk associated with anticipated debt issuances. The Company has locked in a fixed interest rate in exchange for a floating interest rate indexed to the three-month LIBOR.

At March 31, 2017, the Company had outstanding interest-rate swaps with a notional amount of $1.6 billion due prior to or in September 2021 that manage interest-rate risk associated with the potential refinancing of the Company's $900 million Senior Notes due 2019 and the Zero Coupons due 2036, should the Zero Coupons be put to the Company prior to the swap termination dates. At the next put date in October 2017, the accreted value of the Zero Coupons will be $883 million. See *Note 8—Debt*. Depending on market conditions, liability-management actions, or other factors, the Company may enter into offsetting interest-rate swap positions or settle or amend certain or all of the currently outstanding interest-rate swaps.

Derivative settlements and collateralization are classified as cash flows from operating activities unless the derivatives contain an other-than-insignificant financing element, in which case the settlements and collateralization are classified as cash flows from financing activities. As a result of prior extensions of reference-period start dates without settlement of the related interest-rate derivative obligations, the interest-rate derivatives in the Company's portfolio contain an other-than-insignificant financing element, and therefore, any settlements or collateralization related to these extended interest-rate derivatives are classified as cash flows from financing activities. Cash payments related to interest-rate swap agreements were $24 million during the three months ended March 31, 2017, and $193 million during the three months ended March 31, 2016.

The Company had the following outstanding interest-rate swaps at March 31, 2017:

millions except percentages			Mandatory	Weighted-Average
Notional Principal Amount		**Reference Period**	**Termination Date**	**Interest Rate**
$	500	September 2016 – 2046	September 2018	6.559%
$	300	September 2016 – 2046	September 2020	6.509%
$	450	September 2017 – 2047	September 2018	6.445%
$	100	September 2017 – 2047	September 2020	6.891%
$	250	September 2017 – 2047	September 2021	6.570%

7. Derivative Instruments (Continued)

Effect of Derivative Instruments—Balance Sheet The following summarizes the fair value of the Company's derivative instruments:

millions	Gross Derivative Assets		Gross Derivative Liabilities	
Balance Sheet Classification	**March 31, 2017**	December 31, 2016	**March 31, 2017**	December 31, 2016
Commodity derivatives				
Other current assets	**$ 51**	$ 10	**$ (31)**	$ (3)
Other assets	**12**	9	**—**	—
Other current liabilities	**15**	66	**(35)**	(201)
Other liabilities	**—**	—	**—**	(12)
	78	85	**(66)**	(216)
Interest-rate derivatives				
Other current assets	**8**	8	**—**	—
Other assets	**23**	23	**—**	—
Other current liabilities	**—**	—	**(69)**	(48)
Other liabilities	**—**	—	**(1,271)**	(1,328)
	31	31	**(1,340)**	(1,376)
Total derivatives	**$ 109**	$ 116	**$ (1,406)**	$ (1,592)

Effect of Derivative Instruments—Statement of Income The following summarizes gains and losses related to derivative instruments:

millions	Three Months Ended March 31,	
Classification of (Gain) Loss Recognized	**2017**	2016
Commodity derivatives		
Gathering, processing, and marketing sales [(1)]	**$ —**	$ 2
(Gains) losses on derivatives, net	**(135)**	(28)
Interest-rate derivatives		
(Gains) losses on derivatives, net	**(12)**	325
Total (gains) losses on derivatives, net	**$ (147)**	$ 299

(1) Represents the effect of Marketing and Trading Derivative Activities.

7. Derivative Instruments (Continued)

Credit-Risk Considerations The financial integrity of exchange-traded contracts, which are subject to nominal credit risk, is assured by NYMEX or ICE through systems of financial safeguards and transaction guarantees. Over-the-counter traded swaps, options, and futures contracts expose the Company to counterparty credit risk. The Company monitors the creditworthiness of its counterparties, establishes credit limits according to the Company's credit policies and guidelines, and assesses the impact on the fair value of its counterparties' creditworthiness. The Company has the ability to require cash collateral or letters of credit to mitigate its credit-risk exposure.

The Company has netting agreements with financial institutions that permit net settlement of gross commodity derivative assets against gross commodity derivative liabilities and routinely exercises its contractual right to offset gains and losses when settling with derivative counterparties. In addition, the Company has setoff agreements with certain financial institutions that may be exercised in the event of default and provide for contract termination and net settlement across derivative types.

The Company's derivative instruments are subject to individually negotiated credit provisions that may require collateral of cash or letters of credit depending on the derivative's portfolio valuation versus negotiated credit thresholds. These credit thresholds may also require full or partial collateralization or immediate settlement of the Company's obligations if certain credit-risk-related provisions are triggered, such as if the Company's credit rating from S&P and Moody's declines to a level that is below investment grade. As of March 31, 2017, the Company's long-term debt was rated below investment grade (Ba1) by Moody's and investment grade (BBB) by both S&P and Fitch Ratings. Although certain counterparties required the Company to post collateral due to the Moody's rating, no counterparties have requested termination or full settlement of derivative positions. The aggregate fair value of derivative instruments with credit-risk-related contingent features for which a net liability position existed was $1.2 billion (net of $130 million of collateral) at March 31, 2017, and $1.4 billion (net of $117 million of collateral) at December 31, 2016.

7. Derivative Instruments (Continued)

Fair Value Fair value of futures contracts is based on unadjusted quoted prices in active markets for identical assets or liabilities, which represent Level 1 inputs. Valuations of physical-delivery purchase and sale agreements, over-the-counter financial swaps, and commodity option collars are based on similar transactions observable in active markets and industry-standard models that primarily rely on market-observable inputs. Inputs used to estimate fair value in industry-standard models are categorized as Level 2 inputs because substantially all assumptions and inputs are observable in active markets throughout the full term of the instruments. Inputs used to estimate the fair value of swaps and options include market-price curves; contract terms and prices; credit-risk adjustments; and, for Black-Scholes option valuations, discount factors and implied market volatility.

The following summarizes the fair value of the Company's derivative assets and liabilities by input level within the fair-value hierarchy:

millions	Level 1	Level 2	Level 3	Netting [1]	Collateral	Total
March 31, 2017						
Assets						
Commodity derivatives	**$ —**	**$ 78**	**$ —**	**$ (45)**	**$ —**	**$ 33**
Interest-rate derivatives	**—**	**31**	**—**	**—**	**—**	**31**
Total derivative assets	**$ —**	**$ 109**	**$ —**	**$ (45)**	**$ —**	**$ 64**
Liabilities						
Commodity derivatives	**$ (1)**	**$ (65)**	**$ —**	**$ 45**	**$ 2**	**$ (19)**
Interest-rate derivatives	**—**	**(1,340)**	**—**	**—**	**130**	**(1,210)**
Total derivative liabilities	**$ (1)**	**$ (1,405)**	**$ —**	**$ 45**	**$ 132**	**$ (1,229)**
December 31, 2016						
Assets						
Commodity derivatives	$ 2	$ 83	$ —	$ (69)	$ —	$ 16
Interest-rate derivatives	—	31	—	—	—	31
Total derivative assets	$ 2	$ 114	$ —	$ (69)	$ —	$ 47
Liabilities						
Commodity derivatives	$ (3)	$ (213)	$ —	$ 69	$ 6	$ (141)
Interest-rate derivatives	—	(1,376)	—	—	117	(1,259)
Total derivative liabilities	$ (3)	$ (1,589)	$ —	$ 69	$ 123	$ (1,400)

(1) Represents the impact of netting commodity derivative assets and liabilities with counterparties where the Company has the contractual right and intends to net settle.

8. Debt

Debt The following summarizes the Company's outstanding debt, including capital lease obligations, after eliminating the effect of intercompany transactions:

millions	WES	WGP [1]	Anadarko [2]	Anadarko Consolidated
March 31, 2017				
Total borrowings at face value	$ 3,120	$ 28	$ 13,550	$ 16,698
Net unamortized discounts, premiums, and debt issuance costs [3]	(28)	—	(1,587)	(1,615)
Total borrowings [4]	3,092	28	11,963	15,083
Capital lease obligations	—	—	243	243
Less short-term debt	—	—	42	42
Total long-term debt	$ 3,092	$ 28	$ 12,164	$ 15,284
December 31, 2016				
Total borrowings at face value	$ 3,120	$ 28	$ 13,558	$ 16,706
Net unamortized discounts, premiums, and debt issuance costs [3]	(29)	—	(1,599)	(1,628)
Total borrowings [4]	3,091	28	11,959	15,078
Capital lease obligations	—	—	245	245
Less short-term debt	—	—	42	42
Total long-term debt	$ 3,091	$ 28	$ 12,162	$ 15,281

(1) Excludes WES.
(2) Excludes WES and WGP.
(3) Unamortized discounts, premiums, and debt issuance costs are amortized over the term of the related debt. Debt issuance costs related to RCFs are included in other current assets and other assets on the Company's Consolidated Balance Sheets.
(4) The Company's outstanding borrowings, except for borrowings under the WGP RCF, are senior unsecured.

Fair Value The Company uses a market approach to determine the fair value of its fixed-rate debt using observable market data, which results in a Level 2 fair-value measurement. The carrying amount of floating-rate debt approximates fair value as the interest rates are variable and reflective of market rates. The estimated fair value of the Company's total borrowings was $17.0 billion at March 31, 2017, and $17.1 billion at December 31, 2016.

Anadarko Borrowings Anadarko has a $3.0 billion five-year senior unsecured RCF maturing in January 2021 (Five-Year Facility) and a $2.0 billion 364-day senior unsecured RCF (364-Day Facility). In January 2017, the Company extended the maturity date of the 364-Day Facility until January 2018. At March 31, 2017, the Company had no outstanding borrowings under the Five-Year Facility or the 364-Day Facility and was in compliance with all related covenants.

Anadarko's Zero Coupons can be put to the Company in October of each year, in whole or in part, for the then-accreted value, which will be $883 million at the next put date in October 2017. Anadarko's Zero Coupons were classified as long-term debt on the Company's Consolidated Balance Sheet at March 31, 2017, as the Company has the ability and intent to refinance these obligations using long-term debt, should the put be exercised.

In January 2015, the Company initiated a commercial paper program, which allows for a maximum of $3.0 billion of unsecured commercial paper notes and is supported by the Five-Year Facility. The maturities of the commercial paper notes may vary, but may not exceed 397 days. Due to the Company's below-investment-grade credit rating from Moody's, the Company currently does not have access to the commercial paper market and had no outstanding borrowings under the commercial paper program at March 31, 2017.

8. Debt (Continued)

The Company also has notes payable related to its ownership of certain noncontrolling mandatorily redeemable interests that are not included in the Company's reported debt balance and do not affect consolidated interest expense. See *Note 8—Equity Method Investments* in the Company's Annual Report on Form 10-K for the year ended December 31, 2016.

WES and WGP Borrowings At March 31, 2017, WES was in compliance with all related covenants contained in its \$1.2 billion five-year senior unsecured RCF maturing in February 2020 (WES RCF), which is expandable to \$1.5 billion. At March 31, 2017, WES had no outstanding borrowings under its RCF, had outstanding letters of credit of \$5 million, and had available borrowing capacity of \$1.195 billion.

At March 31, 2017, WGP was in compliance with all related covenants contained in its \$250 million three-year senior secured RCF maturing in March 2019 (WGP RCF), which is expandable to \$500 million subject to receiving increased or new commitments from lenders and the satisfaction of certain other conditions. Obligations under the WGP RCF are secured by a first priority lien on all of WGP's assets (not including the consolidated assets of WES) as well as all equity interests owned by WGP. At March 31, 2017, WGP had outstanding borrowings under its RCF of \$28 million at an interest rate of 2.99% and had available borrowing capacity of \$222 million.

9. Income Taxes

The following summarizes income tax expense (benefit) and effective tax rates:

	Three Months Ended March 31,	
millions except percentages	**2017**	2016
Income tax expense (benefit)	**\$ 97**	\$ (383)
Income (loss) before income taxes	**(178)**	(1,381)
Effective tax rate	**(54)%**	28%

The Company reported a loss before income taxes for the three months ended March 31, 2017 and 2016. As a result, items that ordinarily increase or decrease the tax rate will have the opposite effect. The decrease from the 35% U.S. federal statutory rate for the three months ended March 31, 2017, was primarily attributable to the following decreases:

- state taxes, net of federal benefit
- non-deductible Algerian exceptional profits tax for Algerian income tax purposes
- tax impact from foreign operations
- net changes in uncertain tax positions
- tax deficiency related to share-based compensation due to the adoption of ASU 2016-09, see *Note 1—Summary of Significant Accounting Policies*

These decreases were partially offset by the following increases:

- income attributable to noncontrolling interests
- federal manufacturing deduction

The decrease from the 35% U.S. federal statutory rate for the three months ended March 31, 2016, was primarily attributable to non-deductible Algerian exceptional profits tax for Algerian income tax purposes, the tax impact from foreign operations, and net changes in uncertain tax positions.

At March 31, 2017, the Company's Consolidated Balance Sheet included \$167 million of income taxes receivable presented in accounts receivable—others.

10. Contingencies

Litigation There are no material developments in previously reported contingencies nor are there any other material matters that have arisen since the filing of the Company's Annual Report on Form 10-K for the year ended December 31, 2016.

11. Restructuring Charges

In the first quarter of 2016, the Company initiated a workforce reduction program to align the size and composition of its workforce with its expected future operating and capital plans. Employee notifications related to the workforce reduction program were completed by June 30, 2016. The Company recognized $203 million of restructuring charges included in G&A in the Company's Consolidated Statements of Income during the three months ended March 31, 2016. All restructuring charges were recognized in 2016, with the exception of an estimated $29 million of settlement expense expected to be recognized during 2017 for lump-sum payments to terminated participants for which the amount could vary depending on market conditions and participant elections.

12. Pension Plans and Other Postretirement Benefits

The Company has contributory and non-contributory defined-benefit pension plans, which include both qualified and supplemental plans. The Company also provides certain health care and life insurance benefits for certain retired employees. Retiree health care benefits are funded by contributions from the retiree and, in certain circumstances, contributions from the Company. The Company's retiree life insurance plan is noncontributory. The following summarizes the Company's pension and other postretirement benefit cost:

	Pension Benefits		Other Benefits	
millions	**2017**	2016	**2017**	2016
Three Months Ended March 31				
Service cost	**$ 21**	$ 26	**$ —**	$ 1
Interest cost	**21**	26	**3**	3
Expected (return) loss on plan assets	**(21)**	(27)	**—**	—
Amortization of net actuarial loss (gain)	**6**	8	**—**	—
Amortization of net prior service cost (credit)	**—**	—	**(6)**	(6)
Settlement expense	**3**	—	**—**	—
Termination benefits expense [(1)]	**4**	44	**—**	—
Curtailment expense [(1)]	**—**	8	**—**	(3)
Net periodic benefit cost	**$ 34**	$ 85	**$ (3)**	$ (5)

(1) Termination benefits expense and curtailment expense for the three months ended March 31, 2016, relate to the workforce reduction program initiated in the first quarter of 2016. See *Note 11—Restructuring Charges*.

The Company contributed $60 million during the three months ended March 31, 2017, and expects to contribute an additional $107 million to funded pension plans during 2017.

13. Stockholders' Equity

Earnings Per Share The Company's basic earnings per share (EPS) is computed based on the average number of shares of common stock outstanding for the period and includes the effect of any participating securities and Tangible Equity Units (TEUs) as appropriate. Diluted EPS includes the effect of the Company's outstanding stock options, restricted stock awards, restricted stock units, TEUs, and WES Series A Preferred units, if the inclusion of these items is dilutive.

The following provides a reconciliation between basic and diluted EPS attributable to common stockholders:

millions except per-share amounts	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
Net income (loss)		
Net income (loss) attributable to common stockholders	**$ (318)**	$ (1,034)
Income (loss) effect of TEUs	**(2)**	(1)
Basic	**$ (320)**	$ (1,035)
Diluted	**$ (320)**	$ (1,035)
Shares		
Average number of common shares outstanding—basic	**551**	509
Average number of common shares outstanding—diluted	**551**	509
Excluded due to anti-dilutive effect	**11**	10
Net income (loss) per common share		
Basic	**$ (0.58)**	$ (2.03)
Diluted	**$ (0.58)**	$ (2.03)

14. Noncontrolling Interests

WES is a limited partnership formed by Anadarko to acquire, own, develop, and operate midstream assets. During 2016, WES issued 22 million Series A Preferred units to private investors for net proceeds of $687 million, and issued 1.3 million common units to the Company. Proceeds from these issuances were primarily used to acquire interests in Springfield Pipeline LLC from the Company. Pursuant to an agreement between WES and the holders of the Series A Preferred units, 50% of the Series A Preferred units converted into WES common units on a one-for-one basis March 1, 2017, with the remaining Series A Preferred units to be converted in May 2017.

WES Class C units issued to Anadarko will convert into WES common units on a one-for-one basis on the conversion date, which was extended in February 2017 from December 31, 2017, to March 1, 2020. The Class C units receive quarterly distributions in the form of additional Class C units until the March 1, 2020 conversion date unless WES elects to convert the units to common units earlier or Anadarko elects to extend the conversion date. WES distributed 179 thousand Class C units to Anadarko during the three months ended March 31, 2017, and 946 thousand Class C units to Anadarko during 2016.

WGP is a limited partnership formed by Anadarko to own interests in WES. During 2016, Anadarko sold 12.5 million WGP common units to the public for net proceeds of $476 million. At March 31, 2017, Anadarko's ownership interest in WGP consisted of an 81.6% limited partner interest and the entire non-economic general partner interest. The remaining 18.4% limited partner interest in WGP was owned by the public.

At March 31, 2017, WGP's ownership interest in WES consisted of a 29.9% limited partner interest, the entire 1.5% general partner interest, and all of the WES incentive distribution rights. At March 31, 2017, Anadarko also owned an 8.7% limited partner interest in WES through other subsidiaries' ownership of common and Class C units. The remaining 59.9% limited partner interest in WES was owned by the public.

15. Variable Interest Entities

Consolidated VIEs The Company determined that the partners in WGP and WES with equity at risk lack the power, through voting rights or similar rights, to direct the activities that most significantly impact WGP's and WES's economic performance; therefore, WGP and WES are considered VIEs. Anadarko, through its ownership of the general partner interest in WGP, has the power to direct the activities that most significantly affect economic performance and the obligation to absorb losses or the right to receive benefits that could be potentially significant to WGP and WES, therefore Anadarko is considered the primary beneficiary and consolidates WGP and WES. See *Note 14—Noncontrolling Interests* for additional information on WGP and WES.

Assets and Liabilities of VIEs The assets of WGP and WES cannot be used by Anadarko for general corporate purposes and are both included in and disclosed parenthetically on the Company's Consolidated Balance Sheets. The carrying amounts of liabilities related to WGP and WES for which the creditors do not have recourse to other assets of the Company are both included in and disclosed parenthetically on the Company's Consolidated Balance Sheets.

All outstanding debt for WES at March 31, 2017, and December 31, 2016, including any borrowings under the WES RCF, is recourse to WES's general partner, which in turn has been indemnified in certain circumstances by certain wholly owned subsidiaries of the Company for such liabilities. All outstanding debt for WGP at March 31, 2017, and December 31, 2016, including any borrowings under the WGP RCF, is recourse to WGP's general partner, which is a wholly owned subsidiary of the Company. See *Note 8—Debt* for additional information on WGP and WES long-term debt balances.

VIE Financing WGP's sources of liquidity include borrowings under its RCF and distributions from WES. WES's sources of liquidity include cash and cash equivalents, cash flows generated from operations, interest income from a note receivable from Anadarko as discussed below, borrowings under its RCF, the issuance of additional partnership units, or debt offerings. See *Note 8—Debt* and *Note 14—Noncontrolling Interests* for additional information on WGP and WES financing activity.

Financial Support Provided to VIEs Concurrent with the closing of its May 2008 IPO, WES loaned the Company $260 million in exchange for a 30-year note bearing interest at a fixed annual rate of 6.50%, payable quarterly. The related interest income for WES was $4 million for each of the three months ended March 31, 2017 and 2016. The note receivable and related interest income are eliminated in consolidation.

In March 2015, WES acquired the Company's interest in DBJV. The acquisition was financed using a deferred purchase price obligation which requires a cash payment from WES to the Company due on March 31, 2020. The cash payment due to the Company is equal to eight multiplied by the average of WES's share in DBJV Net Earnings (defined below) for 2018 and 2019 less WES's share of capital expenditures incurred for DBJV from March 1, 2015 to February 29, 2020. Net Earnings is defined as all revenues less cost of product, operating expenses, and property taxes. The net present value of this obligation was $37 million at March 31, 2017, and $41 million at December 31, 2016. The reduction in the value of the deferred purchase price obligation was primarily due to revisions reflecting a decrease in WES's estimate of future Net Earnings, partially offset by a decrease in WES's estimate of capital expenditures to be incurred by DBJV.

In order to reduce WES's exposure to a majority of the commodity-price risk inherent in certain of their contracts, Anadarko has commodity price swap agreements in place with WES expiring on December 31, 2017. WES has recorded a capital contribution from Anadarko in its Consolidated Statement of Equity and Partners' Capital for the amount by which the swap price exceeds the applicable market price. WES recorded a capital contribution from Anadarko of $12 million for the three months ended March 31, 2017, and $7 million for the three months ended March 31, 2016.

16. Supplemental Cash Flow Information

Additions to properties and equipment as presented within Anadarko's cash flows from investing activities include cash payments for cost of properties, equipment, and facilities. The cost of properties includes the initial capitalization of drilling costs associated with all exploratory wells whether or not they were deemed to have a commercially sufficient quantity of proved reserves.

The following summarizes cash paid (received) for interest and income taxes, as well as non-cash investing and financing activities:

millions	Three Months Ended March 31, 2017	2016
Cash paid (received)		
Interest, net of amounts capitalized	**$ 308**	$ 299
Income taxes, net of refunds	**1**	(8)
Non-cash investing activities		
Fair value of properties and equipment from non-cash transactions	**$ 549**	$ —
Asset retirement cost additions	**61**	27
Accruals of property, plant, and equipment	**608**	623
Net liabilities assumed (divested) in acquisitions and divestitures	**(82)**	—
Non-cash investing and financing activities		
FPSO construction period obligation [(1)]	**$ —**	$ 2
Deferred drilling lease liability	**7**	—

(1) Upon completion of the FPSO in the third quarter of 2016, the Company reported the construction period obligation as a capital lease obligation based on the fair value of the FPSO.

17. Segment Information

Anadarko's business segments are separately managed due to distinct operational differences and unique technology, distribution, and marketing requirements. The Company's three reporting segments are oil and gas exploration and production, midstream, and marketing. The oil and gas exploration and production segment explores for and produces oil, natural gas, and NGLs and plans for the development and operation of the Company's LNG project in Mozambique. The midstream segment engages in gathering, processing, treating, and transporting Anadarko and third-party oil, natural-gas, and NGLs production as well as gathering and disposal of produced water. The midstream reporting segment consists of two operating segments, WES and other midstream, which are aggregated into one reporting segment due to similar financial and operating characteristics. The marketing segment sells much of Anadarko's oil, natural-gas, and NGLs production as well as third-party purchased volumes.

To assess the performance of Anadarko's operating segments, the chief operating decision maker analyzes Adjusted EBITDAX. The Company defines Adjusted EBITDAX as income (loss) before income taxes; interest expense; DD&A; exploration expense; gains (losses) on divestitures, net; impairments; total (gains) losses on derivatives, net, less net cash from settlement of commodity derivatives; and certain items not related to the Company's normal operations, less net income (loss) attributable to noncontrolling interests. During the periods presented, restructuring charges related to the workforce reduction program included in G&A did not relate to the Company's normal operations.

The Company's definition of Adjusted EBITDAX excludes gains (losses) on divestitures, net and exploration expense as they are not indicators of operating efficiency for a given reporting period. However, exploration expense is monitored by management as part of costs incurred in exploration and development activities. Similarly, DD&A and impairments are excluded from Adjusted EBITDAX as a measure of segment operating performance because capital expenditures are evaluated at the time capital costs are incurred. Adjusted EBITDAX also excludes interest expense to allow for assessment of segment operating results without regard to Anadarko's financing methods or capital structure. Total (gains) losses on derivatives, net, less net cash from settlement of commodity derivatives are excluded from Adjusted EBITDAX because these (gains) losses are not considered a measure of asset operating performance. Finally, net income (loss) attributable to noncontrolling interests is excluded from the Company's measure of Adjusted EBITDAX because it represents earnings that are not attributable to the Company's common stockholders.

Management believes Adjusted EBITDAX provides information useful in assessing the Company's operating and financial performance across periods. Adjusted EBITDAX as defined by Anadarko may not be comparable to similarly titled measures used by other companies and should be considered in conjunction with net income (loss) attributable to common stockholders and other performance measures, such as operating income. Below is a reconciliation of consolidated Adjusted EBITDAX to income (loss) before income taxes:

	Three Months Ended March 31,	
millions	**2017**	2016
Income (loss) before income taxes	**$ (178)**	$ (1,381)
Interest expense	**223**	220
DD&A	**1,115**	1,149
Exploration expense	**1,085**	126
(Gains) losses on divestitures, net	**(804)**	(2)
Impairments	**373**	16
Total (gains) losses on derivatives, net, less net cash from settlement of commodity derivatives	**(155)**	404
Restructuring charges	**(1)**	203
Other operating expense	**—**	1
Less net income (loss) attributable to noncontrolling interests	**43**	36
Consolidated Adjusted EBITDAX	**$ 1,615**	$ 700

17. Segment Information (Continued)

Information presented below as "Other and Intersegment Eliminations" includes corporate costs, results from hard-minerals royalties, net cash from settlement of commodity derivatives, and net income (loss) attributable to noncontrolling interests. The following summarizes selected financial information for Anadarko's reporting segments:

millions	Oil and Gas Exploration & Production	Midstream	Marketing	Other and Intersegment Eliminations	Total
Three Months Ended March 31, 2017					
Sales revenues	**$ 1,524**	**$ 225**	**$ 1,149**	**$ —**	**$ 2,898**
Intersegment revenues	**871**	**361**	**(1,024)**	**(208)**	**—**
Other [1]	**2**	**33**	**6**	**24**	**65**
Total revenues and other [2]	**2,397**	**619**	**131**	**(184)**	**2,963**
Operating costs and expenses [3]	**866**	**317**	**165**	**(43)**	**1,305**
Net cash from settlement of commodity derivatives	**—**	**—**	**—**	**6**	**6**
Other (income) expense, net	**—**	**—**	**—**	**(8)**	**(8)**
Net income (loss) attributable to noncontrolling interests [1]	**—**	**—**	**—**	**43**	**43**
Total expenses and other	**866**	**317**	**165**	**(2)**	**1,346**
Total (gains) losses on derivatives, net included in marketing revenue, less net cash from settlement	**—**	**—**	**(2)**	**—**	**(2)**
Adjusted EBITDAX	**$ 1,531**	**$ 302**	**$ (36)**	**$ (182)**	**$ 1,615**
Three Months Ended March 31, 2016					
Sales revenues	$ 711	$ 125	$ 798	$ —	$ 1,634
Intersegment revenues	601	302	(663)	(240)	—
Other [1]	(1)	13	1	25	38
Total revenues and other [2]	1,311	440	136	(215)	1,672
Operating costs and expenses [3]	773	183	176	(89)	1,043
Net cash from settlement of commodity derivatives	—	—	—	(103)	(103)
Net income (loss) attributable to noncontrolling interests	—	—	—	36	36
Total expenses and other	773	183	176	(156)	976
Total (gains) losses on derivatives, net included in marketing revenue, less net cash from settlement	—	—	4	—	4
Adjusted EBITDAX	$ 538	$ 257	$ (36)	$ (59)	$ 700

(1) Presentation has been adjusted to align with the current analysis of segment performance. Net income (loss) attributable to noncontrolling interests, previously reported within the Midstream segment, is now presented within Other and Intersegment Eliminations. Other revenues, previously reported within Other and Intersegment Eliminations, is now presented within the applicable segments.

(2) Total revenues and other excludes gains (losses) on divestitures, net since these gains and losses are excluded from Adjusted EBITDAX.

(3) Operating costs and expenses excludes exploration expense, DD&A, impairments, restructuring charges, and certain other operating expenses since these expenses are excluded from Adjusted EBITDAX.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

Unless the context otherwise requires, the terms "Anadarko" and "Company" refer to Anadarko Petroleum Corporation and its consolidated subsidiaries. The Company has made in this Form 10-Q, and may from time to time make in other public filings, press releases, and management discussions, forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, concerning the Company's operations, economic performance, and financial condition. These forward-looking statements include, among other things, information concerning future production and reserves, schedules, plans, timing of development, contributions from oil and gas properties, marketing and midstream activities, and also include those statements preceded by, followed by, or that otherwise include the words "may," "could," "believes," "expects," "anticipates," "intends," "estimates," "projects," "target," "goal," "plans," "objective," "should," "would," "will," "potential," "continue," "forecast," "future," "likely," "outlook," or similar expressions or variations on such expressions. For such statements, the Company claims the protection of the safe harbor for forward-looking statements contained in the Private Securities Litigation Reform Act of 1995. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, it can give no assurance that such expectations will be realized. Anadarko undertakes no obligation to publicly update or revise any forward-looking statements whether as a result of new information, future events, or otherwise.

These forward-looking statements involve risk and uncertainties. Important factors that could cause actual results to differ materially from the Company's expectations include, but are not limited to, the following risks and uncertainties:

- *the Company's assumptions about energy markets*
- *production and sales volume levels*
- *levels of oil, natural-gas, and NGLs reserves*
- *operating results*
- *competitive conditions*
- *technology*
- *availability of capital resources, levels of capital expenditures, and other contractual obligations*
- *supply and demand for, the price of, and the commercialization and transporting of oil, natural gas, NGLs, and other products or services*
- *volatility in the commodity-futures market*
- *weather*
- *inflation*
- *availability of goods and services, including unexpected changes in costs*
- *drilling risks*
- *processing volumes and pipeline throughput*
- *general economic conditions, nationally, internationally, or in the jurisdictions in which the Company is, or in the future may be, doing business*
- *the Company's inability to timely obtain or maintain permits or other governmental approvals, including those necessary for drilling and/or development projects*
- *legislative or regulatory changes, including changes relating to hydraulic fracturing; retroactive royalty or production tax regimes; deepwater drilling and permitting regulations; derivatives reform; changes in state, federal, and foreign income taxes; environmental regulation, including regulations related to climate change; environmental risks; and liability under international, provincial, federal, regional, state, tribal, local, and foreign environmental laws and regulations*
- *civil or political unrest or acts of terrorism in a region or country*

- *the creditworthiness and performance of the Company's counterparties, including financial institutions, operating partners, and other parties*
- *volatility in the securities, capital, or credit markets and related risks such as general credit, liquidity, and interest-rate risk*
- *the Company's ability to successfully monetize select assets, repay or refinance its debt, and the impact of changes in the Company's credit ratings*
- *uncertainties associated with acquired properties and businesses*
- *disruptions in international oil and NGLs cargo shipping activities*
- *physical, digital, internal, and external security breaches*
- *supply and demand, technological, political, governmental, and commercial conditions associated with long-term development and production projects in domestic and international locations*
- *other factors discussed below and elsewhere in "Risk Factors" and in "Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Estimates" included in the Company's Annual Report on Form 10-K for the year ended December 31, 2016, this Form 10-Q, and in the Company's other public filings, press releases, and discussions with Company management*

The following discussion should be read together with the *Consolidated Financial Statements* and the *Notes to Consolidated Financial Statements*, which are included in this Form 10-Q in Part I, Item 1; the information set forth in the *Risk Factors* under Part II, Item 1A; the *Consolidated Financial Statements* and the *Notes to Consolidated Financial Statements,* which are included in Part II, Item 8 of the Company's Annual Report on Form 10-K for the year ended December 31, 2016; and the information set forth in the *Risk Factors* under Part I, Item 1A of the Company's Annual Report on Form 10-K for the year ended December 31, 2016.

MANAGEMENT OVERVIEW

In 2017, Anadarko continues to optimize and further concentrate its portfolio on higher-return, oil-levered opportunities in areas where it possesses both scale and competitive advantages, namely the Delaware and DJ basins in the U.S. onshore and deepwater Gulf of Mexico. The GOM Acquisition expanded Anadarko's operated infrastructure and substantial tie-back inventory and doubled its net production from the Gulf of Mexico to approximately 160 MBOE/d, more than 80% of which is comprised of oil. The acquired assets are expected to generate substantial cash flow over the next five years at current strip prices. The Company plans to use the cash flows from the Gulf of Mexico as well as from our international cash generating assets to fund growth in the Company's unconventional assets in the Delaware and DJ basins. The Company ended the first quarter of 2017 with 14 operated drilling rigs in the Delaware basin and 6 operated drilling rigs in the DJ basin, which compares to 9 operated drilling rigs in the Delaware basin and 5 operated drilling rigs in the DJ basin at year-end 2016. In the deepwater Gulf of Mexico, Anadarko has three floating rigs drilling with a focus on leveraging the Company's expansive infrastructure position.

Anadarko currently estimates a 2017 initial capital spending range of $5.4 billion to $5.7 billion, which represents an increase of more than 63% from 2016. The estimated capital spending range includes approximately $900 million to $1.0 billion for WES. The Company has currently allocated approximately 80% of its 2017 capital spending budget to the U.S. onshore upstream and midstream and deepwater Gulf of Mexico; 15% to future value areas, such as deepwater exploration and global LNG; 2% to international cash generation assets, such as oil projects in Algeria and Ghana; and 3% to corporate activities. The Company's 2017 initial capital program was designed to leverage its streamlined portfolio and sharpened focus on higher-margin oil production. The Company will continue to evaluate the oil and natural-gas price environments and may adjust its capital spending plans while maintaining appropriate liquidity and financial flexibility.

As an oil and natural-gas exploration and production company, Anadarko's revenues, operating results, cash flows from operations, capital spending, and future growth rates are highly influenced by commodity prices, which affect the value the Company receives from its sales of oil, natural gas, and NGLs.

Significant operating and financial activities for the first quarter of 2017 include the following:

Total Company

- Anadarko's overall sales-volume product mix increased to 61% liquids in the first quarter of 2017, compared to 53% in the first quarter of 2016, which significantly improved margins.
- Anadarko's first-quarter oil sales volumes averaged 367 MBbls/d, representing a 16% increase from the first quarter of 2016, primarily due to increased volumes from the GOM Acquisition and the startup of TEN offshore Ghana, partially offset by divestitures of U.S. onshore oil and gas assets in 2016 and 2017.

U.S. Onshore

- Oil sales volumes in the Delaware basin increased 10 MBbls/d, representing a 46% increase from the first quarter of 2016, due to increased drilling activity.
- WES acquired a third party's 50% nonoperated interest in the DBJV system in exchange for WES's 33.75% interest in nonoperated Marcellus midstream assets and $155 million in cash.
- Anadarko closed the divestiture of its Eagleford and Marcellus assets during the quarter for net proceeds of $2.8 billion, prior to final closing adjustments.

Gulf of Mexico

- Oil sales volumes averaged 125 MBbls/d, representing a 116% increase from the first quarter of 2016, primarily due to the GOM Acquisition and continued tieback activity at several facilities.

International

- First-quarter sales volumes averaged 104 MBbls/d, representing a 17% increase from the first quarter of 2016, primarily as a result of the TEN development project (19% nonoperated participating interest) in Ghana achieving first oil in the third quarter of 2016.
- Interim mooring of the FPSO at the Jubilee field in Ghana commenced in the fourth quarter of 2016 and was completed during the first quarter of 2017. Final decisions and approvals will be sought for the long-term turret system solution in mid-2017. It is anticipated that a facility shutdown of up to 12 weeks may be required in the second half of 2017. The partnership is actively seeking optimization solutions to minimize the duration of any shutdown period.
- During the quarter, the Company made progress towards finalizing major components of the legal and contractual framework for the LNG project in Mozambique, which will support investment, beginning with the resettlement project, and also position the Company to secure long-term LNG offtake contracts.

Financial

- The Company generated $1.1 billion of cash flow from operations and ended the quarter with $5.8 billion of cash.
- In January 2017, the Company extended the maturity date of the 364-Day Facility until January 2018.

FINANCIAL RESULTS

	Three Months Ended March 31,	
millions except per-share amounts	**2017**	2016
Oil, natural-gas, and NGLs sales	**$ 2,454**	$ 1,394
Gathering, processing, and marketing sales	**444**	240
Gains (losses) on divestitures and other, net	**869**	40
Revenues and other	**$ 3,767**	$ 1,674
Costs and expenses	**3,877**	2,538
Other (income) expense	**68**	517
Income tax expense (benefit)	**97**	(383)
Net income (loss) attributable to common stockholders	**$ (318)**	$ (1,034)
Net income (loss) per common share attributable to common stockholders—diluted	**$ (0.58)**	$ (2.03)
Average number of common shares outstanding—diluted	**551**	509

The following discussion pertains to Anadarko's results of operations, financial condition, and changes in financial condition. Any increases or decreases "for the three months ended March 31, 2017," refer to the comparison of the three months ended March 31, 2017, to the three months ended March 31, 2016. The primary factors that affect the Company's results of operations include commodity prices for oil, natural gas, and NGLs; sales volumes; the cost of finding such reserves; and operating costs.

Revenues and Sales Volumes

	Three Months Ended March 31,			
millions except percentages	**Oil**	**Natural Gas**	**NGLs**	**Total**
2016 sales revenues	$ 850	$ 366	$ 178	$ 1,394
Changes associated with prices	**684**	**210**	**126**	**1,020**
Changes associated with sales volumes	**129**	**(74)**	**(15)**	**40**
2017 sales revenues	**$ 1,663**	**$ 502**	**$ 289**	**$ 2,454**
Increase (decrease) vs. 2016	**96%**	**37%**	**62%**	**76%**

The above table illustrates the effects of the increase in commodity prices and changes associated with sales volumes, which include increases related to the GOM Acquisition (primarily oil) and decreases associated with U.S. onshore asset divestitures (primarily natural gas).

The following provides Anadarko's sales volumes for the three months ended March 31:

	2017	Inc (Dec) vs. 2016	2016
Barrels of Oil Equivalent			
(MMBOE except percentages)			
United States	**62**	(7)%	67
International	**10**	16	8
Total barrels of oil equivalent	**72**	(5)	75
Barrels of Oil Equivalent per Day			
(MBOE/d except percentages)			
United States	**691**	(6)%	738
International	**104**	17	89
Total barrels of oil equivalent per day	**795**	(4)	827

Sales volumes represent actual production volumes adjusted for changes in commodity inventories as well as natural-gas production volumes provided to satisfy a commitment under the Jubilee development plan in Ghana. Anadarko employs marketing strategies to minimize market-related shut-ins, maximize realized prices, and manage credit-risk exposure. For additional information, see *Note 7—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q. Production of oil, natural gas, and NGLs is usually not affected by seasonal swings in demand.

Oil Sales Revenues, Average Prices, and Volumes

	Three Months Ended March 31,		
	2017	Inc (Dec) vs. 2016	2016
Oil sales revenues (millions)	**$ 1,663**	96%	$ 850
United States			
Sales volumes—MMBbls	**24**	15%	21
MBbls/d	**269**	16	232
Price per barrel	**$ 49.23**	76	$ 28.04
International			
Sales volumes—MMBbls	**9**	16%	8
MBbls/d	**98**	18	83
Price per barrel	**$ 53.36**	56	$ 34.11
Total			
Sales volumes—MMBbls	**33**	15%	29
MBbls/d	**367**	16	315
Price per barrel	**$ 50.34**	70	$ 29.65

The following summarizes primary drivers for the change in oil sales revenues:

millions	**Change in Revenues**	**Due to Change in Prices**	**Due to Change in Volumes**
Three months ended March 31, 2017 vs. 2016	$ 813	$ 684	$ 129

Oil Prices

The average oil price received increased for the three months ended March 31, 2017, primarily due to OPEC's agreement to reduce production for the first six months of 2017, which reduced the global oversupply.

Oil Sales Volumes

2017 vs. 2016 The Company's oil sales volumes increased by 52 MBbls/d for the three months ended March 31, 2017, primarily due to the following:

U.S. Onshore

- Sales volumes for the Delaware basin increased by 10 MBbls/d for the three months ended March 31, 2017, primarily due to continued drilling activity.
- Sales volumes for the DJ basin decreased by 16 MBbls/d for the three months ended March 31, 2017, primarily due to reduced capital investment during the low commodity price cycle in 2016.
- Sales volumes for Eagleford decreased by 15 MBbls/d for the three months ended March 31, 2017, primarily due to the sale of the assets in March 2017.

Gulf of Mexico

- Sales volumes increased by 67 MBbls/d for the three months ended March 31, 2017, primarily due to the GOM Acquisition in December 2016.

International

- Sales volumes for Ghana increased by 10 MBbls/d for the three months ended March 31, 2017, primarily due to liftings from the TEN development project, which came online late in the third quarter of 2016.

Natural-Gas Sales Volumes, Average Prices, and Revenues

	Three Months Ended March 31,		
	2017	Inc (Dec) vs. 2016	2016
Natural-gas sales revenues (millions)	**$ 502**	37 %	$ 366
United States			
Sales volumes—Bcf	**167**	(20)%	210
MMcf/d	**1,859**	(19)	2,303
Price per Mcf	**$ 3.00**	71	$ 1.75

The following summarizes primary drivers for the change in natural-gas sales revenues:

millions	**Change in Revenues**	**Due to Change in Prices**	**Due to Change in Volumes**
Three months ended March 31, 2017 vs. 2016	$ 136	$ 210	$ (74)

Natural-Gas Prices

The average natural-gas price Anadarko received increased for the three months ended March 31, 2017, primarily due to the industry's year-over-year production declines. This lower domestic production resulted in lower gas in storage despite lower residential and commercial demand due to warmer than normal temperatures in the first quarter of 2017.

Natural-Gas Sales Volumes

2017 vs. 2016 The Company's natural-gas sales volumes decreased by 444 MMcf/d for the three months ended March 31, 2017, primarily due to the following:

U.S. Onshore

- Sales volumes for Eagleford decreased by 61 MMcf/d for the three months ended March 31, 2017, primarily due to the sale of the assets in March 2017.
- Sales volumes for Marcellus decreased by 43 MMcf/d for the three months ended March 31, 2017, primarily due to natural production declines. The assets were sold on March 31, 2017.
- Sales volumes decreased by 402 MMcf/d for the three months ended March 31, 2017, primarily due to the sale of certain Wyoming and East Texas/Louisiana assets in 2016.

Gulf of Mexico

- Sales volumes increased by 44 MMcf/d for the three months ended March 31, 2017, primarily due to the GOM Acquisition in December 2016.

Natural-Gas Liquids Sales Volumes, Average Prices, and Revenues

	Three Months Ended March 31,		
	2017	Inc (Dec) vs. 2016	2016
Natural-gas liquids sales revenues (millions)	$ 289	62 %	$ 178
United States			
Sales volumes—MMBbls	**10**	(10)%	11
MBbls/d	**112**	(9)	122
Price per barrel	**$ 26.57**	77	$ 14.98
International			
Sales volumes—MMBbls	**1**	14 %	—
MBbls/d	**6**	15	6
Price per barrel	**$ 37.57**	65	$ 22.78
Total			
Sales volumes—MMBbls	**11**	(9)%	11
MBbls/d	**118**	(8)	128
Price per barrel	**$ 27.17**	77	$ 15.32

NGLs sales represent revenues from the sale of product derived from the processing of Anadarko's natural-gas production. The following summarizes primary drivers for the change in NGLs sales revenues:

millions	Change in Revenues	Due to Change in Prices	Due to Change in Volumes
Three months ended March 31, 2017 vs. 2016	$ 111	$ 126	$ (15)

NGLs Prices

The average NGLs price received increased for the three months ended March 31, 2017, primarily due to increased propane and butane prices stemming from higher demand.

NGLs Sales Volumes

2017 vs. 2016 The Company's NGLs sales volumes decreased by 10 MBbls/d for the three months ended March 31, 2017, primarily due to the following:

U.S. Onshore

- Sales volumes for DJ basin increased by 9 MBbls/d for the three months ended March 31, 2017, primarily due to improved well performance.
- Sales volumes decreased by 22 MBbls/d for the three months ended March 31, 2017, primarily due to the sale of certain Wyoming and East Texas/Louisiana assets in 2016.

Gulf of Mexico

- Sales volumes increased by 5 MBbls/d for the three months ended March 31, 2017, primarily due to the GOM Acquisition in December 2016.

Gathering, Processing, and Marketing

millions except percentages	Three Months Ended March 31, 2017	Inc (Dec) vs. 2016	2016
Gathering, processing, and marketing sales	**$ 444**	85%	$ 240
Gathering, processing, and marketing expense	**351**	63	215
Total gathering, processing, and marketing, net	**$ 93**	NM	$ 25

Gathering and processing sales includes revenue from the sale of NGLs and remaining residue gas extracted from natural gas purchased from third parties and processed by Anadarko as well as fee revenue earned by providing gathering, processing, compression, and treating services to third parties. Marketing sales include the margin earned from purchasing and selling third-party oil and natural gas. Gathering, processing, and marketing expense includes the cost of third-party natural gas purchased and processed by Anadarko as well as other operating and transportation expenses related to the Company's costs to perform gathering, processing, and marketing activities.

Gathering, processing, and marketing, net increased by $68 million for the three months ended March 31, 2017, primarily related to an increase in throughput volumes at the DBM complex in the Delaware basin due to downtime throughout the first quarter of 2016 and higher natural-gas and NGLs marketing margins during the first quarter of 2017.

Gains (Losses) on Divestitures and Other, net

millions except percentages	Three Months Ended March 31, 2017	Inc (Dec) vs. 2016	2016
Gains (losses) on divestitures, net	**$ 804**	NM	$ 2
Other	**65**	71%	38
Total gains (losses) on divestitures and other, net	**$ 869**	NM	$ 40

Gains (losses) on divestitures and other, net includes gains (losses) on divestitures and other operating revenues, including hard-minerals royalties, earnings from equity investments, and other revenues.

For the three months ended March 31, 2017, Anadarko divested certain non-core U.S. onshore assets and recognized net gains of $804 million.

See *Note 3—Acquisitions, Divestitures, and Assets Held for Sale* in the *Notes to Consolidated Financial Statements* under Item 1 of this Form 10-Q for additional information.

Costs and Expenses

The following provides Anadarko's total costs and expenses for three months ended March 31:

millions	**2017**	2016
Oil and gas operating	**$ 258**	$ 208
Oil and gas transportation	**249**	242
Exploration	**1,085**	126
Gathering, processing, and marketing	**351**	215
General and administrative	**269**	449
Depreciation, depletion, and amortization	**1,115**	1,149
Production, property, and other taxes	**155**	117
Impairments	**373**	16
Other operating expense	**22**	16
Total	**$ 3,877**	$ 2,538

Oil and Gas Operating Expenses

	Three Months Ended March 31,		
	2017	Inc (Dec) vs. 2016	2016
Oil and gas operating *(millions)*	**$ 258**	24%	$ 208
Oil and gas operating—per BOE	**3.60**	30	2.77

Oil and gas operating expense increased by $50 million for the three months ended March 31, 2017, primarily due to the following:

- higher overall operating costs of $54 million primarily related to the GOM Acquisition
- higher non-operated costs of $32 million in Ghana partially related to the completion of interim mooring of the Jubilee FPSO during the first quarter of 2017 along with production from the TEN development, which came online late in the third quarter of 2016
- lower expenses of $21 million as a result of U.S. onshore asset divestitures

The related costs per BOE increased by $0.83 for the three months ended March 31, 2017, primarily due to increased costs as discussed above and shifting to a higher-return, oil-levered portfolio.

Exploration Expense

millions	Three Months Ended March 31, 2017	2016
Exploration Expense		
Dry hole expense	**$ 476**	$ 11
Impairments of unproved properties	**537**	24
Geological and geophysical expense	**37**	37
Exploration overhead and other	**35**	54
Total exploration expense	**$ 1,085**	$ 126

For the three months ended March 31, 2017, total exploration expense increased by $959 million primarily related to the following:

Dry Hole Expense

Dry hole expense increased by $465 million, primarily due to the following:

- The Company expensed suspended exploratory well costs of $435 million during the three months ended March 31, 2017, related to the Shenandoah project in the Gulf of Mexico. See *Note 5—Suspended Exploratory Well Costs* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.
- The Company expensed $41 million during the three months ended March 31, 2017, due to unsuccessful drilling activities primarily associated with the Gulf of Mexico and an international property.

Impairments of Unproved Properties

- The Company recognized $532 million of impairments of unproved Gulf of Mexico properties during the three months ended March 31, 2017, of which $467 million related to the Shenandoah project. The unproved property balance related to the Shenandoah project originated from the purchase price allocated to the Gulf of Mexico exploration projects from the acquisition of Kerr-McGee Corporation in 2006. See *Note 5—Suspended Exploratory Well Costs* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

General and Administrative Expenses

millions except percentages	Three Months Ended March 31, 2017	Inc (Dec) vs. 2016	2016
General and administrative	**$ 269**	(40)%	$ 449

For the three months ended March 31, 2017, G&A decreased by $180 million primarily due to charges of $203 million in the first quarter of 2016 associated with the workforce reduction program. See *Note 11—Restructuring Charges* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

Impairments

The Company recognized the following impairments:

millions	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016
Oil and gas exploration and production		
U.S. onshore properties	$ —	$ 4
Gulf of Mexico properties	**204**	1
Cost-method investment	—	1
Midstream	**169**	10
Total	**$ 373**	$ 16

Impairments during the three months ended March 31, 2017, were primarily related to oil and gas properties in the Gulf of Mexico due to lower forecasted commodity prices and a U.S. onshore midstream property due to a reduced throughput fee as a result of a producer's bankruptcy.

For further discussion related to impairments, including the potential for future impairments, see *Note 4—Impairments* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

Other (Income) Expense

The following provides Anadarko's other (income) expense for the three months ended March 31:

millions	**2017**	2016
Interest expense	**$ 223**	$ 220
(Gains) losses on derivatives, net [1]	**(147)**	297
Other (income) expense, net	**(8)**	—
Total	$ 68	$ 517

[1] (Gains) losses on derivatives, net represents the changes in fair value of the Company's derivative instruments as a result of changes in commodity prices and interest rates, contract modifications, and settlements. See *Note 7—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Item 1 of this Form 10-Q.

Income Tax Expense (Benefit)

millions except percentages	Three Months Ended March 31, **2017**	Three Months Ended March 31, 2016
Income tax expense (benefit)	**$ 97**	$ (383)
Income (loss) before income taxes	**(178)**	(1,381)
Effective tax rate	**(54)%**	28%

The Company reported a loss before income taxes for the three months ended March 31, 2017 and 2016. As a result, items that ordinarily increase or decrease the tax rate will have the opposite effect. The Company's effective tax rate is impacted each year by the relative pre-tax income (loss) earned by the Company's operations in the U.S., Algeria, and the rest of the world. Additionally, state income taxes (net of federal income tax benefit), non-deductible Algerian exceptional profits tax for Algerian income tax purposes, net changes in uncertain tax positions, and pre-tax income allocated to noncontrolling interest typically impact the Company's effective tax rate. The Company's effective tax rate decreased from 28% for three months ended March 31, 2016, to (54)% for the three months ended March 31, 2017, primarily due to the impact from the items discussed above.

For additional information on income taxes, see *Note 9—Income Taxes* in the *Notes to Consolidated Financial Statements* under Item 1 of this Form 10-Q.

LIQUIDITY AND CAPITAL RESOURCES

millions	Three Months Ended March 31, 2017	2016
Net cash provided by (used in) operating activities	**$ 1,123**	$ (137)
Net cash provided by (used in) investing activities	**1,722**	(973)
Net cash provided by (used in) financing activities	**(198)**	3,119

Overview The Company has a variety of funding sources available, including cash, an asset portfolio that provides ongoing cash-flow-generating capacity, opportunities for liquidity enhancement through divestitures and joint-venture arrangements that reduce future capital expenditures, the Company's credit facilities, and access to both debt and equity capital markets. In addition, an effective registration statement is available to Anadarko covering the sale of WGP common units owned by the Company.

During the first quarter of 2017, Anadarko closed on the divestitures of its U.S. onshore Eagleford and Marcellus assets for net proceeds of $2.8 billion. As of March 31, 2017, Anadarko had $5.8 billion of cash plus $5.0 billion of borrowing capacity under its RCFs. Anadarko believes that its current available cash and anticipated operating cash flows will be sufficient to fund the Company's projected 2017 and long-term operational and capital programs. Current available cash provides the flexibility to accelerate activity in the Delaware and DJ basins or acquire bolt-on positions in these core areas. The Company continuously monitors its liquidity position and evaluates available funding alternatives in light of current and expected conditions.

Operating Activities

One of the primary sources of variability in the Company's cash flows from operating activities is the fluctuation in commodity prices, the impact of which Anadarko partially mitigates by entering into commodity derivatives. Sales volume changes also impact cash flow but historically have not been as volatile as commodity prices. Anadarko's cash flows from operating activities are also impacted by the costs related to operations and interest payments related to the Company's outstanding debt.

Cash provided by operating activities was $1.1 billion for the three months ended March 31, 2017, $1.2 billion higher compared to the same period of 2016. This increase was primarily a result of higher sales revenues in 2017 due to the impact of higher commodity prices and increased oil sales volumes as well as the $159.5 million payment of the Clean Water Act penalty and $79 million related to severance costs in connection with the workforce reduction program in 2016.

Investing Activities

Capital Expenditures The following presents the Company's capital expenditures for the three months ended March 31:

millions	2017	2016
Cash Flows from Investing Activities		
Additions to properties and equipment [(1)]	$ 1,194	$ 1,022
Adjustments for capital expenditures		
Changes in capital accruals	58	(130)
Other	3	4
Total capital expenditures [(2)]	$ 1,255	$ 896

(1) Additions to properties and equipment as presented within Anadarko's cash flows from investing activities include cash payments for cost of properties, equipment, and facilities. The cost of properties includes the initial capitalization of drilling costs associated with all exploratory wells whether or not they were deemed to have a commercially sufficient quantity of proved reserves.

(2) Includes WES capital expenditures of $286 million for the three months ended March 31, 2017, and $140 million for the three months ended March 31, 2016. Capital expenditures exclude the FPSO capital lease asset.

The Company's capital expenditures increased by $359 million for the three months ended March 31, 2017, primarily due to $258 million related to increased U.S. onshore acreage acquisitions and exploration costs in the Gulf of Mexico coupled with increased spending of $154 million related to the development of the Company's midstream assets in the Delaware and DJ basins.

Property Exchange On March 17, 2017, WES acquired a third party's 50% nonoperated interest in the DBJV system in exchange for WES's 33.75% interest in nonoperated Marcellus midstream assets and $155 million in cash. WES funded the cash consideration with cash on hand. After the acquisition, the DBJV system is 100% owned by WES and consolidated by Anadarko. See *Note 3—Acquisitions, Divestitures, and Assets Held for Sale* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

Carried-Interest Arrangements In the third quarter of 2014, the Company entered into a carried-interest arrangement that requires a third party to fund $442 million of Anadarko's capital costs in exchange for a 34% working interest in the Company's Eaglebine development, located in Southeast Texas. The third-party funding is expected to cover Anadarko's future capital costs in the development through 2020. At March 31, 2017, $151 million of the $442 million carry obligation had been funded.

Divestitures During the three months ended March 31, 2017, Anadarko received net proceeds of $2.9 billion from divestitures, primarily related to the sale of the Company's U.S. onshore Eagleford and Marcellus oil and gas assets. See *Note 3—Acquisitions, Divestitures, and Assets Held for Sale* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

Financing Activities

millions except percentages		March 31, 2017		December 31, 2016
Anadarko	$	**12,206**	$	12,204
WES		**3,092**		3,091
WGP		**28**		28
Total debt	$	**15,326**	$	15,323
Total equity		**15,079**		15,497
Debt to total capitalization ratio		**50.4%**		49.7%

Debt Activity

Anadarko RCFs Anadarko has a $3.0 billion Five-Year Facility that matures in January 2021 and a $2.0 billion 364-Day Facility. In January 2017, the Company extended the maturity date of the 364-Day Facility until January 2018. At March 31, 2017, the Company had no outstanding borrowings under the Five-Year Facility or the 364-Day Facility.

WES and WGP RCFs WES has a $1.2 billion RCF that matures in February 2020 and is expandable to $1.5 billion. At March 31, 2017, WES had no outstanding borrowings under its RCF, had outstanding letters of credit of $5 million, and had available borrowing capacity of $1.195 billion.

WGP has a $250 million RCF that matures in March 2019 and is expandable to $500 million, subject to receiving increased or new commitments from lenders and the satisfaction of certain other conditions. At March 31, 2017, WGP had outstanding borrowings under its RCF of $28 million at an interest rate of 2.99% and had available borrowing capacity of $222 million.

For additional information on the Company's RCFs, see *Note 8—Debt* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

Debt Maturities At March 31, 2017, Anadarko's scheduled debt maturities during 2017 consisted of $34 million of senior amortizing notes associated with the TEUs. Anadarko's Zero Coupons can be put to the Company in October of each year, in whole or in part, for the then-accreted value, which will be $883 million at the next put date in October 2017.

For additional information on the Company's debt instruments, see *Note 8—Debt* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

Equity Transactions WES can issue common units to the public under its $500 million continuous offering program, which allows for an aggregate of $500 million of WES common units. The remaining amount available to be issued under this program was $442 million at March 31, 2017.

During the first quarter of 2016, WES issued 14 million Series A Preferred units to private investors for net proceeds of $440 million. In April 2016, WES issued an additional eight million Series A Preferred units to private investors, pursuant to the full exercise of an option granted in connection with the initial issuance, and raised net proceeds of $248 million.

For additional information on WES Series A Preferred units, see *Note 14—Noncontrolling Interests* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

Derivative Instruments For information on derivative instruments, including cash flow treatment, see *Note 7—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

Common Stock Dividends Anadarko paid dividends to its common stockholders of $28 million during the three months ended March 31, 2017, and $25 million during the three months ended March 31, 2016. In response to the commodity-price environment, the Company decreased the quarterly dividend from $0.27 per share to $0.05 per share in February 2016. Anadarko has paid a dividend to its common stockholders quarterly since becoming a public company in 1986.

The amount of future dividends paid to Anadarko common stockholders is determined by the Board on a quarterly basis and is based on the Company's earnings, financial conditions, capital requirements, the effect a dividend payment would have on the Company's compliance with relevant financial covenants, and other factors deemed relevant by the Board.

Distributions to Noncontrolling Interest Owners Distributions to noncontrolling interest owners primarily relate to the following for the three months ended March 31:

millions	**2017**	2016
WES distributions to unitholders (excluding Anadarko and WGP) [(1)]	$ 68	$ 63
WES distributions to Series A Preferred unitholders [(2)]	15	—
WGP distributions to unitholders (excluding Anadarko) [(3)]	19	11

(1) WES has made quarterly distributions to its unitholders since its IPO in the second quarter of 2008 and has increased its distribution from $0.30 per common unit for the third quarter of 2008 to $0.875 per common unit for the first quarter of 2017 (to be paid in May 2017).

(2) WES has made quarterly distributions of $0.68 per unit, prorated based on issuance date, to its Series A Preferred unitholders since the unit issuances in March and April 2016 (to be paid in May 2017).

(3) WGP has made quarterly distributions to its unitholders since its IPO in December 2012 and has increased its distribution from $0.17875 per common unit for the first quarter of 2013 to $0.49125 per unit for the first quarter of 2017 (to be paid in May 2017).

RECENT ACCOUNTING DEVELOPMENTS

See *Note 1—Summary of Significant Accounting Policies* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q for discussion of recent accounting developments affecting the Company.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The Company's primary market risks are attributable to fluctuations in energy prices and interest rates. These risks can affect revenues and cash flows, and the Company's risk-management policies provide for the use of derivative instruments to manage these risks. The types of commodity derivative instruments used by the Company include futures, swaps, options, and fixed-price physical-delivery contracts. The volume of commodity derivatives entered into by the Company is governed by risk-management policies and may vary from year to year. Both exchange and over-the-counter traded derivative instruments may be subject to margin-deposit requirements, and the Company may be required from time to time to deposit cash or provide letters of credit with exchange brokers or counterparties to satisfy these margin requirements. For additional information relating to the Company's derivative and financial instruments, see *Note 7—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

COMMODITY-PRICE RISK The Company's most significant market risk relates to prices for oil, natural gas, and NGLs. Management expects energy prices to remain unpredictable and potentially volatile. As energy prices decline or rise significantly, revenues and cash flows are likewise affected. In addition, a non-cash write-down of the Company's oil and gas properties or goodwill may be required if commodity prices experience a significant decline. Below is a sensitivity analysis for the Company's commodity-price-related derivative instruments.

Derivative Instruments Held for Non-Trading Purposes The Company had derivative instruments in place to reduce the price risk associated with future production of 25 MMBbls of oil and 284 Bcf of natural gas at March 31, 2017, with a net derivative asset position of $4 million. Based on actual derivative contractual volumes, a 10% increase in underlying commodity prices would reduce the fair value of these derivatives by $111 million, while a 10% decrease in underlying commodity prices would increase the fair value of these derivatives by $110 million. However, any cash received or paid to settle these derivatives would be substantially offset by the sales value of production covered by the derivative instruments.

Derivative Instruments Held for Trading Purposes At March 31, 2017, the Company had a net derivative asset position of $9 million on outstanding derivative instruments entered into for trading purposes. Based on actual derivative contractual volumes, a 10% increase or decrease in underlying commodity prices would not materially impact the Company's gains or losses on these derivative instruments.

INTEREST-RATE RISK Borrowings, if any, under each of the 364-Day Facility, the Five-Year Facility, the WES RCF, and the WGP RCF are subject to variable interest rates. The balance of Anadarko's long-term debt on the Company's Consolidated Balance Sheets has fixed interest rates. The Company has $2.9 billion of LIBOR-based obligations that are presented on the Company's Consolidated Balance Sheets net of preferred investments in two noncontrolled entities. These obligations give rise to minimal net interest-rate risk because coupons on the related preferred investments are also LIBOR-based. While a 10% change in LIBOR would not materially impact the Company's interest cost, it would affect the fair value of outstanding fixed-rate debt.

At March 31, 2017, the Company had a net derivative liability position of $1.3 billion related to interest-rate swaps. A 10% increase (decrease) in the three-month LIBOR interest-rate curve would decrease (increase) the aggregate fair value of outstanding interest-rate swap agreements by $91 million. However, any change in the interest-rate derivative gain or loss could be substantially offset by changes in actual borrowing costs associated with future debt issuances. For a summary of the Company's outstanding interest-rate derivative positions, see *Note 7—Derivative Instruments* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

Anadarko's Chief Executive Officer and Chief Financial Officer performed an evaluation of the Company's disclosure controls and procedures as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (Exchange Act). The Company's disclosure controls and procedures are designed to ensure that information required to be disclosed by the Company in reports it files or submits under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission, and to ensure that the information required to be disclosed by the Company in reports that it files or submits under the Exchange Act is accumulated and communicated to the Company's management, including the principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure. Based on this evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that the Company's disclosure controls and procedures are effective as of March 31, 2017.

Changes in Internal Control over Financial Reporting

There were no changes in Anadarko's internal control over financial reporting during the first quarter of 2017 that materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The Company is a defendant in a number of lawsuits and is involved in governmental proceedings and regulatory controls arising in the ordinary course of business, including personal injury and death claims; title disputes; tax disputes; royalty claims; contract claims; contamination claims relating to oil and gas exploration, development, production, transportation, and processing; and environmental claims, including claims involving assets owned by acquired companies and claims involving assets previously sold to third parties and no longer a part of the Company's current operations. Anadarko is also subject to various environmental-remediation and reclamation obligations arising from federal, state, tribal, and local laws and regulations. While the ultimate outcome and impact on the Company cannot be predicted with certainty, after consideration of recorded expense and liability accruals, management believes that the resolution of pending proceedings will not have a material adverse effect on the Company's financial condition, results of operations, or cash flows.

WGR Operating, LP, a wholly owned subsidiary of the Company, is currently in negotiations with the EPA with respect to alleged noncompliance with the leak detection and repair requirements of the Clean Air Act at its Granger, Wyoming facilities. Although management cannot predict the outcome of settlement discussions, it is likely a resolution of this matter will result in a fine or penalty in excess of $100,000.

Anadarko E&P Onshore LLC, a wholly owned subsidiary of the Company, is currently in negotiations with the Pennsylvania Department of Environmental Protection concerning enforcement over a produced water release in Pennsylvania in 2015. Although management cannot predict the outcome of settlement discussions, it is likely a resolution of this matter will result in a fine or penalty in excess of $100,000.

Kerr-McGee Oil and Gas Onshore, LP, a wholly owned subsidiary of the Company, is currently in negotiations with the State of Colorado's Department of Public Health and Environment with respect to alleged noncompliance with the Colorado Air Quality Control Commission's Regulations. Although management cannot predict the outcome of settlement discussions, it is likely a resolution of this matter will result in a fine or penalty in excess of $100,000.

See *Note 10—Contingencies* in the *Notes to Consolidated Financial Statements* under Part I, Item 1 of this Form 10-Q, which is incorporated herein by reference, for a discussion of material legal matters that have arisen since the filing of the Company's Annual Report on Form 10-K for the year ended December 31, 2016.

Item 1A. Risk Factors

There have been no material changes from the risk factors included under Part I, Item 1A of the Company's Annual Report on Form 10-K for the year ended December 31, 2016.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

The following sets forth information with respect to repurchases by the Company of its shares of common stock during the first quarter of 2017:

Period	Total number of shares purchased [(1)]	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs	Approximate dollar value of shares that may yet be purchased under the plans or programs
January 1 - 31, 2017	21,117	$ 71.08	—	$ —
February 1 - 28, 2017	2,968	$ 69.47	—	$ —
March 1 - 31, 2017	307,298	$ 62.52	—	$ —
Total	331,383	$ 63.13	—	$ —

(1) During the first quarter of 2017, all purchased shares related to stock received by the Company for the payment of withholding taxes due on employee share issuances under share-based compensation plans.

Item 6. Exhibits

Exhibits designated by an asterisk (*) are filed herewith or double asterisk (**) are furnished herewith; all exhibits not so designated are incorporated herein by reference to a prior filing under File Number 1-8968 as indicated.

	Exhibit Number		Description
	3	(i)	Restated Certificate of Incorporation of Anadarko Petroleum Corporation, dated May 21, 2009, filed as Exhibit 3.3 to Form 8-K filed on May 22, 2009
		(ii)	By-Laws of Anadarko Petroleum Corporation, amended and restated as of September 15, 2015, filed as Exhibit 3.1 to Form 8-K filed on September 21, 2015
	10	(i)	First Amendment to 364-Day Revolving Credit Agreement, dated January 13, 2017, among Anadarko Petroleum Corporation, JPMorgan Chase Bank, N.A., as administrative agent, and the additional lenders party thereto, filed as Exhibit 10.1 to Form 8-K filed on January 20, 2017
*	31	(i)	Rule 13a-14(a)/15d-14(a) Certification—Chief Executive Officer
*	31	(ii)	Rule 13a-14(a)/15d-14(a) Certification—Chief Financial Officer
**	32		Section 1350 Certifications
*	101	.INS	XBRL Instance Document
*	101	.SCH	XBRL Schema Document
*	101	.CAL	XBRL Calculation Linkbase Document
*	101	.DEF	XBRL Definition Linkbase Document
*	101	.LAB	XBRL Label Linkbase Document
*	101	.PRE	XBRL Presentation Linkbase Document

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ANADARKO PETROLEUM CORPORATION
(Registrant)

May 2, 2017

By: /s/ ROBERT G. GWIN

Robert G. Gwin
Executive Vice President, Finance and Chief Financial Officer

Exhibit 119

Marathon sells Shenandoah stake

oedigital.com/news/449676-marathon-sells-shenandoah-stake

Offshore Engineer April 12, 2016

April 12, 2016

Marathon Oil has agreed to sell its 10% stake in the giant Shenandoah oil discovery in the US Gulf of Mexico as part of a major sell-off of assets.

The firm has already sold out most of its major assets in the Gulf of Mexico. In November last year, Marathon announced it had agreed to sell all its operated and producing assets in the Gulf of Mexico, as well as a tranche of non-operated assets, leaving it with, at the time, interests in some producing assets and interests in the Gunflint development and Shenandoah.

Shenandoah is operated by Anadarko and was discovered in 2013 in the Walker Ridge block in about 5800ft water depth. Anadarko continued its appraisal work on the field last year, encountering more than 620ft of net oil pay on the Shenandoah-4 side-track. In its 2015 full year report the firm said it "continued to progress this giant oil discovery toward development." The Shenandoah-4 appraisal well was due to be drilling in Q1 this year.

Today, Marathon also announced agreements to sell off various onshore assets, in a deal amounting to $950 million, bringing its total divestment program to about $1.3 billion since last year.

Marathon didn't disclose who it had made the deals with and said the Shenandoah sale was part of a number of separate transactions worth some $80 million.

"Since August 2015, we have now announced or closed non-core asset sales of approximately $1.3 billion, surpassing our targeted range of $750 million to $1 billion," said Marathon Oil president and CEO Lee Tillman. "Ongoing portfolio management continues to drive the simplification and concentration of our portfolio to lower risk, higher return US resource plays and support our 2016 objective of balance sheet protection."

Deepwater North America Gulf of Mexico